FUEL SUBSTITUTION IN STEAM ELECTRIC POWER GENERATION

A Thesis Submitted
in Partial Fulfilment of the Requirements
for the Degree of

DOCTOR OF PHILOSOPHY

By

ANANTADEB BHATTACHARYYA

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DEPARTMENT OF HUMANITIES AND SOCIAL SCIENCES
INDIAN INSTITUTE OF TECHNOLOGY KANPUR

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DEDICATED TO

MY PARENTS

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CERTIFICATE I

Certified that the work presented in this thesis entitled, 'FUEL SUBSTITUTION IN STEAM ELECTRIC POWER GENERATION' by Mr. Anantadeb Bhattacharyya has been carried out under our supervision and that this has not been submitted elsewhere for a degree.

R R Barthwal
(R.R. Barthwal)
Professor of Economics
Department of Humanities
and Social Sciences,
I.I.T. Kanpur, India.

TVS Rammohan Rao
(T.V.S. Rammohan Rao)
Professor of Economics
Department of Humanities
and Social Sciences,
I.I.T. Kanpur, India.

DEPARTMENT OF HUMANITIES AND SOCIAL SCIENCES

INDIAN INSTITUTE OF TECHNOLOGY, KANPUR, INDIA

CERTIFICATE II

This is to certify that Mr. Anantadeb Bhattacharyya has satisfactorily completed all the course requirements for the Ph.D. degree programme in Economics. The courses include :

M	607	Applied Numerical Methods
ECO	731	Advanced Monetary Theory and Macro Dynamics
ECO	732	Econometrics
ECO	736	Industrial Organization and Policy
ECO	737	Development Economics
ECO	739	Price Theory
HSS	800	Research

Mr. Anantadeb Bhattacharyya was admitted to the candidacy of the Ph.D. degree programme in March 1980 after he successfully completed the written and oral qualifying examinations.

9.7.83
Head,
Department of Humanities
and Social Sciences

Convenor, 9/7/83
Departmental Post-Graduate
Committee

GLOSSARY OF TERMS USED IN POWER SYSTEM

AVAILABILITY RATE : It is the ratio of available Megawatt hours in a given period to the total Megawatt hours that the power plant is capable of generating at full load during the entire period under reference. It is expressed in percentage. For a power station having a single unit, this will mean the ratio of available hours to the total hours in the period whereas in the case of a multi-unit power station, it is calculated as the percentage ratio of sum of the products of capacity and available hours of individual units to the product of total capacity of station and number of hours in the reference period.

BASE LOAD : It is the minimum load over a given period of time.

BOILER EFFICIENCY : It is $[W_1(H-H_f)]/(W_2.CV)$ in percentage, where W_1 is the weight of the steam generated in pounds, W_2 is the weight of the fuel burned in pounds, H is the total heat of the steam in BTU per pound, H_f is the total heat of the feedwater entering the economizer in BTU per pound and CV is the calorific value of fuels in BTU per pound.

BRITISH THERMAL UNIT (BTU) : It is defined as the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

CAPACITY UTILIZATION RATE (CU) : It is the ratio of the electrical energy produced in a given period to the maximum possible energy that could have been produced had the generating capacity been operating continuously at its maximum level during the entire period under reference. It is expressed in percentage.

DERATED CAPACITY : It is the decrease in the installed or rated capacity of the generating unit due to age or defects in any of its components.

DIVERSITY FACTOR : It is the sum of the maximum demands of different consumers as a proportion of the actual maximum simultaneous demand of the system as a whole.

ENERGY INPUT : It enters most process equipment as chemicals/ materials in the form of fossil fuels, as sensible enthalpy in fluid streams, as latent heat in vapour streams or as electric current.

ENERGY LOSS : Energy is lost to the ambient environment from the process equipment through friction, and radiative and convective heat transfer. Radiative heat loss takes place by means of light and other electromagnetic radiation, whereas convective heat transfer occurs when the surface of hot material is displaced by cool gas.

ENERGY CONSERVATION : It can be defined as the substitution of energy for capital, labour, or material and time. This definition also covers the substitution of scarce type of energy source (e.g., oil) for that of abundant type (e.g., coal).

ENTROPY : It is defined as $dS = dQ/T$ where dS is an increment of entropy and dQ is the infinitesimal (reversible) heat transfer at absolute temperature T. The entropy S is equal to S_o for a perfectly ordered system and increases with increasing disorder (i.e., with greater randomness). Randomness reduces the strength of energy that theoretically can be transformed into useful work.

EXERGY : It is defined as the available work. Availability is defined as the maximum work that can be obtained from a material or material stream by bringing the material to complete equilibrium with the environment by reversible processes.

FORCED OUTAGE RATE (FOR) : It is the ratio of the Megawatt hours under forced shutdown in a given period to the total Megawatt hours that the power plant is capable of generating at full load during the entire period under reference. It is expressed in percentage. For a power station having a single unit, this will mean the ratio of the forced outage hours to the total hours

in the period whereas in the case of a multi-unit power station, it reduces the operating capacity to the extent and for the duration any one or more units are under forced shutdown.

FREQUENCY : It is the rotation of the L.P. blades in turbines measured as the number of cycles per second.

GENERATING UNIT : It is an electric generator together with its prime mover. A prime mover is the engine, turbine water wheel or similar machine which drives an electric generator.

GENERATION : It is the total amount of electrical energy produced by the generating units in a generating station or stations. This is also called as gross generation.

HEAT RATE (HR) : It represents the Kilocalories (Kcal) chargeable to the turbine per unit of useful output, i.e., per horse power hour or per Kilowatt hour (kWh). The heat rates of turbo-generator units are expressed in Kcal per kWh available at the generator terminals. The turbine heat rate is $(H_T + Q_R - (H_F - H_C) - H_E)/(\text{output in KW})$, where H_T is the heat content of the steam supplied in the boiler side of the throttle valve and strainer, in Kcal/hour; Q_R is the heat added to the steam by reheating, equal to the increase in the heat content from the point at which the steam leaves the turbine to be reheated to the point at which the reheated steam re-enters the turbine casing,

in Kcal/hour; H_F is the heat content of feedwater leaving the highest temperature heater, in Kcal/hour; H_C is the heat content of condenser at the temperature actually prevailing in the condenser hotwell during the test, in Kcal/hour; and H_E is the heat content of water at the temperature of the boiling point corresponding to the absolute pressure prevailing at the turbine exhaust flange, in Kcal/hour.

INSTALLED CAPACITY (IC) : It is also called as name-plate capacity. It is the full load continuous rating of a generator, prime mover or other electrical equipment under specified conditions as designated by the manufacturer. It is usually indicated on a name plate attached mechanically to the individual machine or device. The name-plate rating of a steam electric turbine generator set is the guaranteed continuous output in Megawatts or Kilowatts or KVA and power factor at generator terminals when the turbine is clean and operating under specified throttle steam pressure and temperature, reheat temperature, exhaust pressure, and with full extraction from all extraction openings.

KILOWATT HOUR (kWh) : It is the basic unit of electrical energy, equal to one Kilowatt of power supplied to or taken from an electric circuit steadily for one hour. One kWh is equal to 3412.8 BTU or 1.34 horsepower/hour.

LAWS OF ENERGY CONSERVATION (THERMODYNAMICS) : The first law of Thermodynamics indicates that energy can neither be created nor destroyed, it can only be changed from one form to another. The Second Law of Thermodynamics states that spontaneous heat flow is always unidirectional from a hot body to a cold one, never the reverse, and the entropy of an isolated system increases in such a process.

MEGAWATT (MW) : One Megawatt (MW) is equal to 10^6 watts. Watt is the electrical unit of power or the rate of doing work. It is the rate of energy transfer equivalent to one ampere flowing under a potential difference of one volt at unity power factor. It is analogous to horsepower or foot-pounds per minute of mechanical power. One horsepower is equivalent to approximately 746 watts.

MERIT-ORDER LOADING : It means the connection of the units to the load according to their costs in an ascending order. That is, lowest cost unit is loaded first and is followed up by units with relatively higher cost until the demand on the system is provided for.

PARTIAL OUTAGE : It denotes the energy loss when the turbo-generator is hot, but not connected to the load.

PARTIAL UNAVAILABILITY RATE : It is defined as the energy lost during the period the plant was not available for generation at full capacity as a percentage of the energy that could have been produced if the plant had generated at the maximum capacity.

PEAK (MAXIMUM) LOAD : It is the maximum simultaneous ultimate customer demand which occurs during the period under reference as measured by actual deliveries at bulk power sources. It includes line losses but no auxiliary power requirements.

PEAKING CAPABILITY : It is the capacity that is available from a particular unit to meet the peak demand at any time.

PEAKING CAPACITY : It is the sum of the peaking capabilities of the different power generating units in the system.

PLANNED OUTAGE RATE (POR) : It is the ratio of the Megawatt hours under planned shutdown in a given period to the maximum Megawatt hours that the unit is capable of generating. It is expressed in percentage. For a single generating unit station, this will mean the ratio of planned outage hours to the total hours in the period whereas in the case of a power station having more than one unit, it reduces the operating capacity to the extent and for the period any one or more units are under planned shutdown.

PLANNED UTILIZATION RATE (PUR) : It is (1-POR) expressed in percentage.

PLANT EFFICIENCY : It is the ratio of the total energy consumed by the plant to the total energy produced by the plant. That is, it means the ratio of heat equivalent of the operations of the Rankine Vapour Cycle to net enthalpy of the liquid measured in Kcal per Kg.

PLANT LOAD FACTOR (PLF) : It is the average load over a period as a proportion of the maximum (i.e., peak) load over the same period under consideration.

RANKINE EFFICIENCY (VAPOUR CYCLE) : A steam engine operating at a top temperature of 212°F and an exhaust temperature of 80°F would add 132 BTU at an average temperature of (212+80)/2 or 146°F, and would add 970BTU at a temperature of 212°F, thus making a weighted mean temperature of heat addition of 203°F or 663°R. The Rankine Efficiency of this cycle, then, is (663-540)/663 or 18.6 percent. Computation may change slightly due to varying heat capacity of liquid water as temperature changes.

REGIONAL GRID : It is a control centre from which inter-State transfers of energy of various power stations are directed.

RELIABILITY : The reliability of a power system is defined with reference to two indices of risk viz., (i) the expected value of the energy not supplied over a certain period of time on the assumption that the adjustment of load to availability is carried out, and (ii) the expected value of the power disconnected without forewarning during the period of time as a consequence of the unavailability of the elements of the system.

SPINNING RESERVE : It is the capacity which is running and available on the generating station bus-bars to meet the variations of load demand or unforeseen outages of machines. It is also designated as gross plant margin.

SYSTEM LOAD FACTOR : It is the average peak load of units as a percentage of the maximum peak load of the system as a whole.

THERMAL : It is a term used to identify a type of electrical generating station, capacity or capability or output in which the source of energy for the prime mover is heat.

THERMAL EFFICIENCY : It is the ratio of heat rate (HR) to the minimum Kilocalories required to produce one kWh (i.e., 860 Kcal or 3412.8 BTU).

WORK : It is an interaction between a system (e.g., boiler) and its surroundings (e.g., turbines). It is done by a system on its surroundings if the sole external effect of the interaction could be the movement of a desired mass in the surroundings. Its magnitude is equal to the product of the force and the displacement of its point of application in the direction of the force. In case of steam electric power generation, the force is generated by heated steam from the boiler, and the work done is the turning of turbines. The magnitude of work done is measured by the number and the force of turns made by the turbines.

SYNOPSIS

Over the past several years there was a steady increase in the demand for power from various sectors of the Indian Economy. The process of economic development may be considered as the genesis of this trend. Significant attempts were made to augment the supply potential in response to these demands.

The relative share of thermal power plants was significantly large over time though it was originally expected that hydro power generation would constitute the basic source of supply. It appears that thermal power would remain an important source of supply in the foreseeable future.

However, despite significant capacity expansion, there has been a widespread shortage of power. It is necessary to identify the factors responsible for the shortage so that much of the chronic load shedding can be eliminated by appropriate corrective policy.

A systematic attempt can be initiated by defining the provision of power as efficient if a Kilowatthour of energy is delivered at the lowest possible cost. The possibility that there are inefficiencies in actual operation is indicated by two common observations. (i) There has been a substantial difference between the planned utilization rate and the actual capacity utilization. (ii) The actual heat rate and the fuel-mix combinations in use are widely different from the technologically determined optima.

The observed inefficiency may itself be due to one or more of the following factors : (i) System inefficiency in the choice of installed capacity, (ii) inefficient planning in the determination of the rates of utilization, and (iii) operational inefficiency due to improper choice of fuel-mix and consequently the heat rate.

These aspects can be examined appropriately only when the institutional and technological constraints on the decision making process are kept in perspective. To this end it was felt that the following dimensions of the problem should be accounted for : (i) The decisions regarding installed capacity and actual operations are entrusted to different levels of management who presumably have different objectives. (ii) The supply process is made inherently stochastic due to the existence of forced and partial outages. The input choices must account for this aspect efficiently. (iii) The inputs and outputs of steam electric power plants are multi-dimensional and each of these aspects has a differential impact on the overall cost. (iv) The <u>ex ante</u> and <u>ex post</u> input choices are not identical. Any analytical framework which attempts to integrate these factors should also be able to distinctly identify the extent of inefficiency attributable to each of the three dimensions mentioned earlier.

A perusal of the literature indicated three primary methods of examining the fuel substitution possibilities in the context of power plant economics : (i) the production function approach, (ii) the input demand approach, and (iii) an analysis of the cost functions. Extensive search of the analytical as well as empirical experiences indicated that the cost function approach is the most efficacious. Consequently, the study was developed on this basis.

Structurally, the hierarchical form of decision making necessitated writing the cost function for the capital cost component and operating costs separately. This had to be done in the deterministic as well as stochastic formulations. Secondly, the multi-output and *ex ante* versus *ex post* distinctions were incorporated in both the cost equations following established conventions. Thirdly, the effect of stochastic supply variation on input choices was introduced by recognizing that forced outages require revaluation of the utilization rates and fuel-mix choices. The formulation enabled us to demonstrate that the different forms of inefficiency can be isolated by using this approach.

Empirical work is reported for a sample of twenty six power plants based on their monthly performance. Firstly, a synthetic cross-section was developed with reference to the peak demand quarter in an year to examine the optimality of the *ex ante* choices of installed capacity, rate of utilization, and

fuel-mix. The results indicated that the actual installed capacity is generally close to the optimum determined by minimum cost considerations. Allowing for the stochastic variations improved the closeness of these two figures. However, the actual rate of capacity utilization differed considerably from the optimal. Thus, it appears that despite appropriate choice of installed capacity, there was inefficiency in the planned rates of use. Secondly, cost estimates were obtained for each plant on the basis of the monthly time series data. Optimal levels of planned utilization rate, capacity utilization rate, and fuel-mix were developed for both the deterministic and stochastic variations. It was demonstrated that there were significant disparities between the observed PUR, CU, heat rate and fuel-mix, and the optimal values so computed. The actual heat rate and fuel-mix were not optimal even if the observed PUR and CU were taken to be optimal. Similarly, the analysis clearly indicated that the operational management was inefficient. They perhaps do not undertake cost minimization strategies as much as they ought to.

A monthly simulation of the different aspects of inefficiency was then undertaken to analyze the possible differences in the performance at different load factors. A direct relationship between load and efficiency was discernable. In otherwords, the operational management of power plants tends to be reasonably

efficient only when there is a necessity to deliver large volumes of energy.)

In general, the pattern of behaviour exhibited by this study is similar to the earlier results developed for the public sector undertakings and the corporate sector. Far more attention to the different aspects of operational management is required if the existing installed capacity has to deliver the requisite power efficiently.

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CHAPTER 1

INTRODUCTION

1.1 ELECTRIC POWER GENERATION

The technology of electric power generation has been the subject of intense empirical study. Electric power is produced by creating heat energy from diverse fuels and converting it into electricity mechanically[1]. The heat energy is itself generated by a combination of capital and fuel inputs according to well-defined technological relationships[2]. Other inputs, including production labour,

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1. The heat energy, supplied by the combustion of fossil fuel in conventional steam plants, is used to convert water into superheated steam at high pressure and temperature within a boiler. This superheated steam is then introduced into a turbine where it is expanded to a lower temperature and pressure, thereby converting the heat energy of the steam into rotational energy. The rotational energy of the turbine is then converted into electrical energy by directly connecting the turbine to an electrical generator. Since both boiler and generator losses are minimal, the efficiency characteristic of this BTG (Boiler Turbine Generator) process can be measured in terms of the thermal efficiency of the steam cycle.

2. The primary design parameters, accounting for the thermal efficiency of a BTG unit of a given size, are turbine throttle (maximum) pressure and temperature, number of reheat units, and number of feedwater heaters in the steam cycle. The pressure-temperature combination is designated as the steam quality or condition. With a given steam condition, increases in both the number of reheat stages and feedwater heaters will enhance the thermal efficiency of the steam cycle but at a decreasing rate. Current practices for maximum size units utilize eight or nine stages of feedwater heating and two stages of reheat (double reheat), both of which are fuel-saving but require additional capital inputs.

maintenance labour and materials are complementary in the production process.

The output of an electric power generating plant[3] can usefully be thought of as being two-dimensional. The first dimension, which can be designated as power, is usually measured in Kilowatts (KW's) and can be taken as the instantaneous rate of output. The second dimension, energy, is usually measured in Kilowatthours (KWh). This is a measure of the cumulative output over a well-defined interval of time. Thus, if the instantaneous rate at time t is KW(t), then the cumulative output over the time period (O,T) can be defined by $kWh = \int_0^T KW(t)dt$. However, empirical studies often consider kWh's as the scalar measure of output.

The generation technology does not permit electricity to be economically stored. Hence, any given plant must have sufficient capacity to meet the maximum instantaneous demand that is likely to occur during a given interval of time. However, most electric utilities are multi-plant operations. Consequently, the sum of the capacities of the individual units in the plant must match or exceed the expected maximum

3. A unit is the collection of capital equipment performing the function of converting the energy contained in the fossil fuel into electricity. A plant/station, at a given physical location, may house more than one generating unit.

instantaneous rate of demand for power at the bus-bar. Usually, the plant size or, installed capacity, will be chosen to satisfy the expected maximum instantaneous demand for power. The operating procedures, given the installed capacity, will be defined in such a way as to deliver a given time profile of energy and consequently rate of capacity utilization. It is also clear that a given installed capacity will not be available, for power generation, at every instant of time due to either preventive maintenance or forced outages. The managers at the operating level would have to determine the optimal shutdown schedule for maintenance as well as the optimal fuel-mix to deliver the exogenously determined demand for energy. Thus, both the dimensions of output have a significant role in the decision making process of the management of the power generating unit.

The capital equipment of an electric power generating unit, in turn, has two characteristics. The first is the size of the generating unit. The unit size is the maximum instantaneous rate of output which the unit is capable of producing. The second is the efficiency of the unit[4].

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4. The fuel efficiency of a unit is the quantity of fuel the unit requires to produce a unit of electrical energy (Kilocalories/kWh), as related to the minimum thermal equivalent of 860 Kcal per kWh.

These dimensions are embedded in the capital equipment. The thermodynamic relationships, between steam conditions and technically optimal capital (turbine) size, result in larger capacity turbine generator units having better thermal efficiencies.

The process of generating electricity must conform to the physical laws of thermodynamics. Given the law of conservation of energy, it is physically impossible to produce a kWh of electricity with less than 3413 BTU (British Thermal Units)[5] or 860 Kilocalories (Kcal) of fuel. However, this ideal is never really accomplished due to metallurgical reasons. The fuel efficiency of most of the steam electric power plants is only of the order of 30-40 percent. Direct observation confirms that plants of various fuel efficiencies are in operation.

1.2 ECONOMICS OF POWER GENERATION

The electric utility faces a load duration curve that describes the time pattern of instantaneous demand for power over a period of time. The utility recognizes the load duration curve as given and is required to meet the load as

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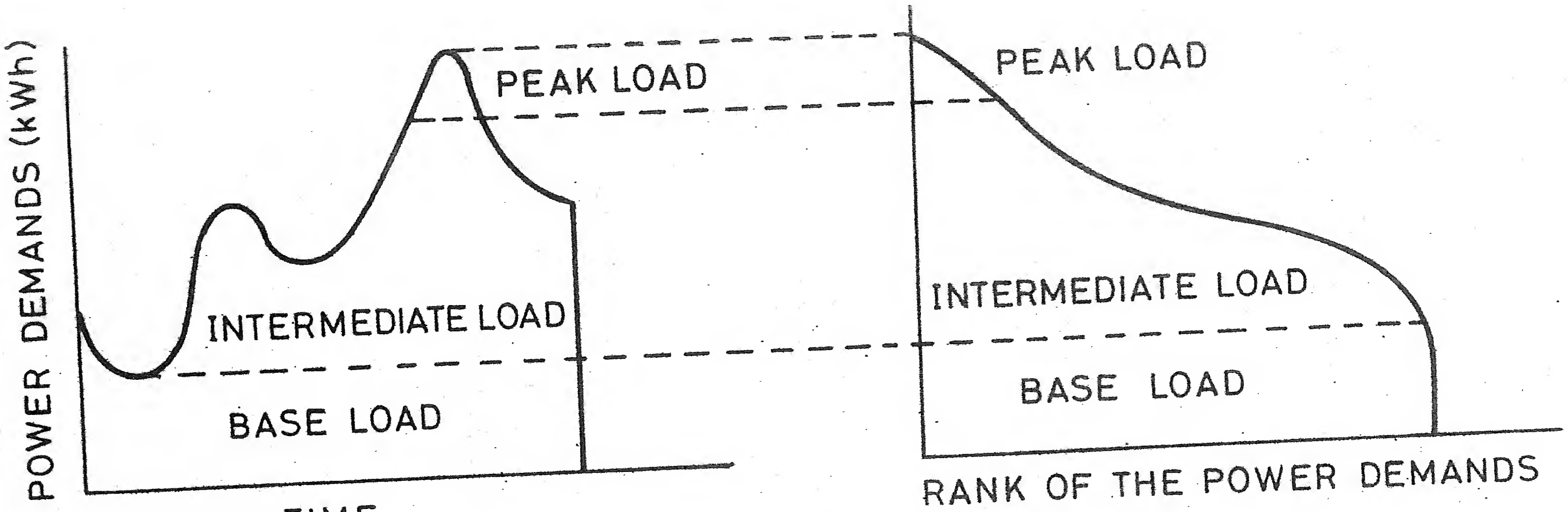
5. A British Thermal Unit or BTU is defined as the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

it occurs. Power demand varies continuously during a day, over a week, and from one season to another. The flow of electrical energy (power demand) is plotted over a given period of time to obtain a chronological load curve. A typical daily load curve is presented in Figure 1.1(a) where the power demand (P) is plotted as a function of time (t).

A load duration curve (LDC) is the plot of the load data reorganized in such a way as to indicate the number of hours of the day over which the load is above or below a predetermined value. Hence, the chronological load data are put in a descending order and plotted against the rank of each item of the load information.

A typical load duration curve is shown in Figure 1.1(b) where the power demand P is represented as a function of the number of hours or days ($P = \Psi(\tau)$) without reference to any specific time of the day. The areas under the chronological load curve and the load duration curve are identical. They represent the total quantity of electrical energy, E. Thus, $E = \int_0^T f(t)dt = \int_0^\tau \Psi(\tau)d\tau$.

The total energy supplied by the utility's generating plants is usually divided into three parts : the base load (to be supplied 100 percent of the time), the peak load (to be supplied during very short periods), and intermediate



(a) CHRONOLOGICAL LOAD CURVE

(b) LOAD DURATION CURVE

FIG.1-1 NATURE OF THE LOAD DURATION CURVE

load (see Figure 1.2). These three load categories are usually performed by different types of generating equipment. Generally, the base generating plants are more likely to have relatively higher investment costs and lower operating costs than the peak generating plants. There is an optimum mix of generating plants and an optimum generating schedule in order to satisfy the load at minimum cost.

We need two parameters to define the load duration curve, e.g., (i) the plant load factor (PLF), and (ii) the plant loss factor. The PLF is defined as

$$\frac{\text{average power demand}(P_{av})}{\text{maximum demand }(P_{max})}$$

The average power demand being the area under the curve divided by the base

$$P_{av} = \frac{\int_0^T f(t)\,dt}{T}$$

Power losses occur when an electric current passes through a conductor. Most of these losses are converted into heat which dissipates into the atmosphere. These resistive losses vary from 3 to 20 percent depending upon the voltage. The overall resistive losses (L) vary according to the square of the power demand, as derived from the physical law

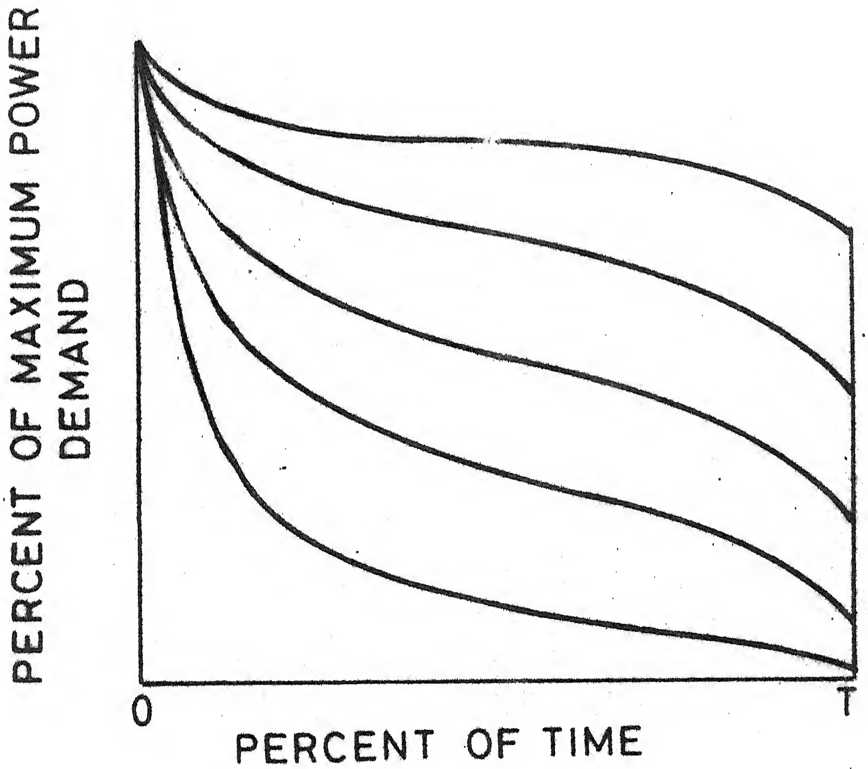


FIG.1.2 LOAD DURATION CURVES

$$L = KP^2 = K\ f(t)^2$$

Thus, the loss factor is defined as

$$\frac{\text{average power losses}}{\text{maximum power losses}}$$

The average power loss (L_{av}) is given by

$$\frac{K \int_{0}^{t_1} f(t)^2\, dt}{t_1}$$

The load factor (PLF) controls the vertical displacement of the load duration curve (LDC), whereas the loss factor causes a rotation of the curve. The LDC is expressed by

$$P_r(p > P) = 1 - P_r\ (p \leq P)$$

$$= 1 - \frac{1}{\sqrt{2\pi}} \int_{-\infty}^{Z_1} e^{-Z^2/2}\, dZ$$

where $Z = \frac{\ln P - \mu_1}{\sigma_1}$, μ_1 and σ_1 being mean and standard deviation of the log of the power demand respectively.

Thus, the LDC indicates the percentage of time over which the power demand is greater than a certain value (the curve of $P_r(p > P)$). It can be rotated to appear in the form of a probability function i.e., $P_r(p \leq P)$. But, the maximum power demand in the above expression is

undetermined. One has to choose the best probability density function to solve the problem of the undetermined maximum power demand. Generally, the log-normal distribution is chosen.

From this we obtain

$$PLF = \frac{\mu}{P_{max}} \quad , \quad \text{and the loss factor} = \frac{\sigma^2+\mu^2}{P^2_{max}} ,$$

where μ and σ are respectively the mean and standard deviation of the random variable, P. P_{max} is now determined by choosing the most appropriate normal variate, Z_1 and using it in the equation

$$P_{max} = \exp(\sigma_1 Z_1 + \mu_1)$$

where μ_1 and σ_1 are the mean and standard deviation of the normal variate, log P.

Thus, the LDC is defined by either μ and σ of the power demand or the load factor and loss factor of the power system.

The primary decisions of an electric utility concerned are the mix of fuel, plant types, and the sizes of the individual units to be installed. Given the LDC, the present study seeks to analyze the choices of plant/unit size and input-mix in the context of investment planning models.

Though the determination of fuel-mix and plant size are not independent, it is useful to consider them separately when examining the basic economic forces involved. The fuel-mix decision is made by finding an economic balance between investment and operating cost. To understand this balance, it is useful to start with an LDC which expresses demand for an operating period in terms of a set of distinct components. The plant sizing decision is concerned with the problem of finding an optimum balance between economies of scale and the opportunity cost of temporary excess capacity. The stochastic nature of electricity supply affects optimal plant size in so far as there is a need for greater excess capacity to satisfy a given expected peak load. Thus, random plant availability introduces a diseconomy of scale with respect to plant size. Consequently, an efficient operational plan is necessary for the viability of the electric power generating plants.

1.3 THE PLANNING AND ORGANIZATION[6]

Planning for the power sector follows much the same process as in other sectors. The national plan for power forms a part of the Annual and Five-Year Plans. The power sector is controlled jointly by the States and the Central Government.

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6. Much of the analysis of the present Section is based on The Committee on Power (1980) and The World Bank Country Study (1979).

The organizational structure of the power sector is given in Figure 1.3. Apart from the Planning Commission, the Department of Power (in the Ministry of Energy), and the Central Electricity Authority (CEA) are the two Central Government agencies most closely associated with development of power plants. Within the CEA, the planning department comprises of three directorates : the Power Survey Directorate, the Progress and Plan Directorate, and the Technical Examination and Co-ordination Directorate. The first is responsible for preparing the Annual Power Survey (APS) with the help of four Regional offices. The second provides the Secretariat for the Working Groups on power. The third is responsible for the techno-economic appraisal of all power generation and transmission schemes submitted by the State Governments for clearance and inclusion in the Plan.

The plan for power starts with a forecast of demand. The APS methodology applies both a load factor and a loss factor to convert demand for energy into a requirement for power at the bus-bar in every State. Margins for spinning

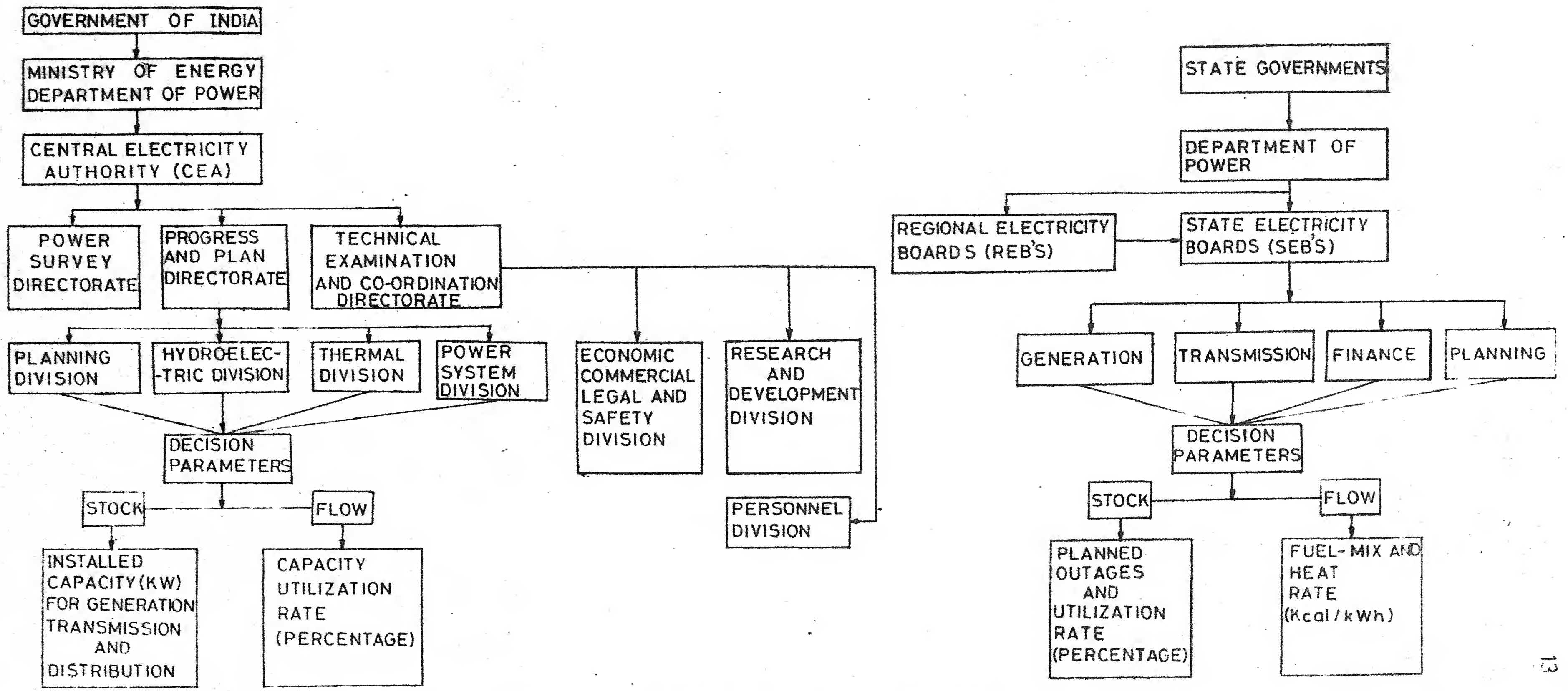

FIG-1·3 HIERARCHICAL STRUCTURE OF THE POWER SECTOR

reserves[7], and forced and partial outages[8], raise the power requirement figure to a target for generating capacity. The annual need for additional power generating capacity can be obtained from this estimate. The Working Group develops investment plans to meet these needs. Such plans result in a schedule of specific generation and transmission projects.

Individual projects, originating with a State Electricity Board (SEB), must be approved by the CEA and sanctioned by the Planning Commission for inclusion in the Plan. They are assessed primarily on the basis of their capacity to meet the requisite State level load and on their technical feasibility. Once the plant(s) is (are) installed, the operation and management decisions are entrusted to the respective SEB's.

Thus, at the system level, the CEA - along with the Planning Commission and the Department of Power in the Ministry of Energy takes decisions with respect to the

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7. Spinning reserve is defined as the capacity which is running and available on the generating plant bus-bars to meet the variations of load demand or unforeseen outages of machines.

8. The Forced Outage Rate is the total number of hours in the year, the plant was shutdown due to breakdowns as a percentage of 8760 (i.e., 365x24) hours. A partial outage denotes the energy loss when the turbo-generator is hot, but not connected to the load.

stock of power generating capacity as well as the flow of power supply in the country. The stock decision pertains to the choice of the capacity, to be installed in different Regions/States, to satisfy the exogenously determined load requirement. The choice of installed capacity determines, and is in turn determined by, the optimal flow rate of capacity utilization given the load pattern on the system and the generally accepted technical norms for power plant maintenance.

The SEB's, set up under the Electricity (Supply) Act 1948, exist in all States except in the States of Sikkim, Nagaland, Manipur and Tripura and the Union Territories. The SEB's generally co-ordinate the development of power generating capacity, and the supply and distribution of electricity within the State. The SEB's are largely autonomous in matters relating to operations though they are subject to State Government direction regarding investment and tariff policy.

The Regional Electricity Boards (REB's) were established during 1964-66 to help develop integrated power

systems in their respective Regions[9]. The 1948 Electricity Supply Act was amended in 1976 wherein the CEA was also authorized to supervise the setting up and operation of generating stations (plants) in the public sector. The most recent legislation to affect the power sector was the 1978 amendment of the financial provisions of the 1948 Act. As a result of this amendment, the SEB's are expected to generate a surplus after meeting all expenses, properly chargeable to revenues, including operation and maintenance expenses, taxes, depreciation and interest.

Thus, during the phase of operational decisions, the SEB's determine the following stock and flow variables

(i) Stock decisions with respect to planned outages and maintenance, i.e., planned utilization rate[10] (percentage), and

9. Regions are defined geographically e.g., North, East, South, West and North-East. We have five REB's to co-ordinate planning and operation of the Electricity Supply Undertakings in respective Regions. The Regional Grids are control centres from which inter-State transfers of energy of various power stations are controlled. Inter-State transfers of energy constitute about 15 percent of the total energy generated in the country.

10. Planned Utilization Rate = (1-Planned Outage Rate), where Planned Outage Rate is the ratio of the Megawatt hours under planned shutdown in a given period to the maximum Megawatt hours that the unit is capable of generating. It is expressed in percentage.

(ii) flow decisions regarding fuel-mix and heat rate (Kcal/kWh).

1.4 OBSERVATIONS ON OBSERVED DECISION PROCESSES[11]

The power supply industry registered a phenomenal rate of growth for power during the last three decades due to rising demand. The installed generation capacity increased thirteen-fold from 2300 MW in 1950-51 to 29217 MW by the end of 1978-79. The industry generated 110032 million kWh of electrical energy during 1978-79 as compared to 6575 million kWh in 1950-51.

Within the power sector, the mix between thermal and hydro electric generation has changed only slightly over the last thirty years. The contribution of the hydel power units has fallen from 49 percent to 46 percent while that of the thermal power units increased from 47 percent to 51 percent in terms of the total supply of electrical energy.

The capacity planning process has three major characteristics. Firstly, it has only a Five-Year time horizon. Secondly, planning for new capacity is done on a State-wise basis. There is no evidence of any useful co-ordination

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11. The quantitative information of this Section is basically obtained from The Committee on Power (1980). and The World Bank Country Study (1979).

of plans from the different States within a Regional grid. Thirdly, projects get approved on a 'first come first served' basis. There is no shelf of projects to choose from.

Historically, during the early plan periods, power development in different Regions was undertaken with the basic objective of developing hydel projects and providing thermal capacity to account for any residual demand. Augmentation of thermal capacity was considered necessary to produce power over a shorter time horizon. The hydro-thermal mix in the different Regions developed in such a way as to meet most of the system requirements in the Northern and Southern Regions despite the ad hoc approach to Regional planning. There is need for additional peak capacity in the Western Region. The lack of adequate hydro-electric development has been a serious constraint to meeting peak demands as well as for optimal utilization of the thermal capacity in the Eastern Region. Thus, we notice that installation of thermal capacity in different Regions is not undertaken on an optimal basis with respect to peak requirements[12].

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12. There is a marked shift in emphasis towards thermal power stations(plants)in recent years. This is basically a result of the recognition that the hydro power potential is inadequate and nuclear power cannot as yet offer a viable alternative.

Before examining the performance of the thermal plants, it is necessary to consider the maximum attainable capacity utilization for a given set of system conditions. The plant availability depends upon the proportion of time that the plant is shutdown for planned maintenance, and for unforeseen breakdowns, i.e., forced outages. The Planned Utilization Rate, which is defined as (1-Planned Outage Rate), is a decision parameter for individual thermal plants. It is determined at the unit or plant hierarchy level. Taking international norms, and the actual performance of thermal power plants into account, 80 percent plant availability is considered as a reasonable working norm.

Translating plant availability into an attainable capacity utilization rate for each plant is a complex exercise which requires analysis of partial breakdowns, the shape of the load duration curve, and the merit-order loading[13] of the plant. As an expert judgement, the Committee on Power (1980) advocated a capacity utilization rate of 58 percent as a reasonable average norm for thermal

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13. Merit-order loading means connecting the units to the load according to their costs in an ascending order. That is, lowest cost unit is loaded first and is followed up by units with relatively higher cost until the demand on the system is provided for.

plants. If the system is operated efficiently, the difference between 80 percent and 58 percent would be largely attributable to lack of demand[14].

The actual rate of capacity utilization in thermal plants has been much lower than even this expected rate. However, the reason for this is not the lack of demand. Instead, it was observed that the forced outages and partial outages far exceed what can be considered normal on technical and managerial considerations. As a result, the demands on the system could not be met[15].

Outages are a main problem for thermal power plants. Monitoring past performance by the CEA suggested that margins of 3.5 percent for planned outages, 18.5 percent

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14. A small allowance has to be made for partial unavailability arising out of the full capacity not being generated due to unforeseen breakdowns in parts of the plant, lack of fuel and so on. The margin for spinning reserve is taken as 5 percent and auxiliaries for thermal power plants are assumed to be 10 percent. This figure is set high to reflect the electricity used to handle and crush coal, and supply to the power plant colonies.

15. Besides availability, derating of installed capacity (i.e., decrease in the capacity due to age or defects in component) has also a considerable bearing on the capacity utilization. The Working Group on Energy Policy (1979) provided an allowance of 0.5 percent per year to cover derating and retirement on an *ad hoc* basis. The Electricity Supply Act, 1948, as amended in March 1978 specified 25 years as the life of thermal plants.

for forced outages, and 10 percent for partial outages may be appropriate for planning purposes. On the other hand, the Tenth Annual Power Survey (APS) specified 10 percent for forced outages and 10 percent for planned outages without making any separate assumption about partial outages. The total allowance for forced and planned outages is about the same.

Table 1.1 presents an analysis of the actual performance of thermal plants on an All-India basis for the past seven years.

These figures reflected the generally low thermal power plant efficiency. A particularly steep fall in thermal capacity utilization has been observed during the years 1978-79 and 1979-80. The fact that 5 percent to 7.5 percent of the plant availability[16] was lost due to lack of demand in conditions of severe power shortages indicates the scope for the integration of Regional grids into a National grid so as to ensure effective demand management.

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16. The Availability Rate represents the total number of hours in the year the plant was available for generation (i.e., 8760 - planned and forced outage hours) as a proportion of 8760 hours.

TABLE 1.1 PERFORMANCE OF THERMAL POWER PLANTS

ear	Planned outages (percentage)	Planned utilization Rate (percentage)	Forced Outages (percentage)	Plant Availability (percentage)	Partial Unavailability (percentage)	Lack of Demand	Capacity Utilization (percentage)
73-74	19.9	80.1	8.8	71.2	20.8	-	50.4
74-75	13.2	86.8	10.5	76.3	23.6	-	52.7
75-76	15.8	84.2	10.3	73.9	22.0	-	51.9
76-77	9.8	90.8	13.2	77.0	14.4	7.3	55.3
77-78	13.4	86.6	14.2	72.4	14.3	5.4	52.7
78-79	14.3	85.7	14.7	71.0	16.2	5.3	49.5
79-80	12.3	87.7	18.8	68.9	17.5	6.0	45.4

URCE : The Committee on Power (1980), p.123.

In order to examine the causes of partial unavailability[17], which results in a decrease in the plant availability rate, we should analyze outages in detail. The CEA's review of outages of thermal power plants (1977-78) also clearly brought out the disturbing practice of postponing annual boiler overhaul (ABO) and capital maintenance (CM) of turbo-generators (TG). The broad picture is presented in Table 1.2.

Under the law, every boiler should be taken out for planned maintenance once a year and the figures corresponding to boilers under ABO should be 100 percent. The figures show that the position is deteriorating and the number of boilers and turbines which are long overdue for maintenance is increasing. That 39 boilers have not been overhauled for 3 years is not only a source of plant inefficiency but also presents a serious safety risk. See Table 1.3.

Although the time taken for boiler maintenance is decreasing, there is no indication of any improvement in the quality of maintenance. TG sets are to be overhauled

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17. Partial Unavailability is defined as the energy lost during the period the plant was not available for generation at full capacity as a percentage of the energy that could have been produced if the plant had generated at full capacity.

TABLE 1. 2 MAINTENANCE OF BOILERS

	1975-76	1976-77	1977-78	1978-79
a. Number of Boilers and TG sets	137	145	153	162
b. Boilers under ABO	44 (32)	40 (28)	37 (24)	36 (22)
c. TG under maintenance (CM)	22 (16)	4 (10)	23 (15)	12 (7)
d. Number of days for boiler maintenance[1]	68	42	37	40
e. Number of days for TG maintenance[2]	126	71	70	105

NOTE : Figures in brackets are percentages

1. Kulkarni Committee recommended 28 days
2. Kulkarni Committee recommended 45 days.

SOURCE : The Committee on Power (1980), p.131.

TABLE 1.3 NUMBER OF UNITS NOT OVERHAULED

	1 Year	2 Years	3 Years
Boilers	30	23	39
Turbines	-	-	85

NOTE : The reference year for this table is 1977-78.

SOURCE : The Committee on Power (1980), p.131.

once in every three years. Hence, the figures for TG's under maintenance should be nearer 33 percent of the total number in operational use. Thus, the maintenance picture is unsatisfactory.

The inadequate attention to planned maintenance has inevitably resulted in increasing forced outage rates (FOR) of thermal plants which reached an overall figure of 14 percent in 1977-78. However, a significant proportion (over 60 percent) of this has been contributed by units commissioned since 1973-74. This can be noted from Table 1.4.

Older plants, which are wearing out, are normally expected to show high rates of forced outages. However, the reverse appears to be true in the case of thermal power plants. One of the reasons is that the older plants, though thermodynamically less efficient, are smaller and less sophisticated and presumably easier to maintain and operate.

A perusal of Table 1.5 suggests that during the last 2 to 3 years the proportion of forced outages caused by turbo-generators has become markedly higher than that contributed by others.

TABLE 1.4 FORCED OUTAGE RATE (FOR) FOR PLANTS OF DIFFERENT VINTAGES

Year of commissioning	FOR (percentage)
1976-77	32.55
1975-76	24.49
1974-75	41.00
1973-74	28.95
1970-73	14.06
1965-69	12.29
1960-64	6.64
1955-59	1.72
1950-54	2.54

SOURCE : The Committee on Power (1980), p. 133.

TABLE 1.5 CONTRIBUTION OF DIFFERENT CAPITAL UNITS TO FORCED OUTAGE RATE (FOR)

UNIT	1975-76 (percentage)	1976-77 (percentage)	1977-78 (percentage)
Boiler	41.2	33.77	33.18
Turbine	10.3	26.72	31.09
Generator	19.7	28.09	22.44
Others	28.8	11.42	11.29

SOURCE : The Committee on Power (1980), p.133.

The Boiler Turbine Generators(BTG) specific heat rate (*ex ante*)[18] for individual power plants can be obtained from Table 1.6. Actual (*ex post*) heat rates have also been tabulated for the purpose of comparison. The name-plate heat rates deviate widely from the actual heat rate mainly due to (i) improper maintenance and overhauling of BTG sets, and (ii) unbalanced moisture and ash content and volatile matter in different grades of coal for coal-fired boilers[19].

For example, the BTG set of the Durgapur Power Projects Ltd. (DPPL) has a designed heat rate of 2365 Kcal/kWh at 77 MW and 2324 Kcal/kWh at 66 MW of load. Equivalently, the boiler efficiency is expected to be 88.75 percent, 88.65 percent and 88.55 percent at 60 percent, 80 percent and 100 percent load respectively. Thus, the *ex ante* heat rate varies even within a given plant for different heating cycles.

The deviation between *ex ante* and *ex post* heat rate should be analyzed with respect to maintenance hazards, uneconomic fuel usages and low grades of fuel.

The upshot of the foregoing analysis is a recognition that (i) there has been a substantial difference between the

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18. For technical details regarding how these name-plate heat rates are computed, refer to Vishnu (1971).

19. The calorific value of coal should be 8100 BTU/lb with maximum moisture content of 10 percent, ash content of 40 percent and volatile matter of 19-20 percent. For details, refer to Datta (1966), and Banerjee (1969).

TABLE 1.6

COMPARISON OF A SAMPLE OF THERMAL POWER STATIONS (PLANTS)

Sl. No.	Name of the Thermal Power Plant	Location (State)	Installed capacity in MW	Capacity utilization in (percentage)	Planned utilization rate in (percentage)	Forced outage rate in (percentage)	Heat Rate (ex ante) KCal/kWh	Heat rate (ex post) KCal/kWh
1	2	3	4	5	6	7	8	9
1.	Gurunanakdeb (Bhatinda)	Punjab	440.00	36.27	90.38	33.18	2365.00	3081.88
2.	Faridabad	Haryana	120.00	33.62	88.91	29.10	2500.00	3704.14
3.	Panipat	Haryana	220.00	34.06	97.04	32.54	2600.00	4066.57
4.	Indraprastha	Delhi	284.10	63.81	88.71	16.03	2324.00	3461.48
5.	Badarpur	Delhi	510.00	49.96	86.70	22.25	2520.00	3417.32
6.	Nasik	Maharashtra	280.00	63.84	93.64	10.01	2305.00	2531.32
7.	Bhusawal(I)	Maharashtra	62.50	73.00	83.19	5.81	2500.00	3321.00
8.	Bhusawal(II	Maharashtra	210.00	43.16	81.57	22.01	2365.00	3229.20
9.	Paras	Maharashtra	92.50	64.85	83.82	4.36	2600.00	3300.72
10.	Koradi	Maharashtra	680.00	59.11	93.09	13.34	2069.00	2217.92

contd ...

1	2	3	4	5	6	7	8	9
11.	Parli Vaijnatu	Maharashtra	60.00	85.83	85.89	4.73	2500.00	3286.31
12.	Trombay(Tata)	Maharashtra	337.50	68.49	82.64	2.95	2500.00	2978.67
13.	Dhuvaran	Gujrat	534.00	69.64	95.62	2.24	2365.00	2785.52
14.	Ukai	Gujrat	640.00	37.50	94.15	34.05	2365.00	3048.34
15.	Kothagudam (A)	Andhra Pradesh	240.00	50.21	84.05	3.45	2500.00	3114.92
16.	Kothagudam (B)	Andhra Pradesh	220.00	21.52	90.59	48.18	2500.00	3703.09
17.	Kothagudam (C)	Andhra Pradesh	220.00	32.29	85.91	52.83	2500.00	3301.63
18.	Ramagundam (B)	Andhra Pradesh	62.50	68.56	88.03	5.71	2365.00	2787.35
19.	Neyveli Lignite Corp.Ltd.	Tamil Nadu	600.00	61.01	88.06	9.48	2365.00	3405.18
20.	Ennore	Tamil Nadu	450.00	36.79	75.68	19.26	2500.00	3236.94
21.	Basin Bridge	Tamil Nadu	90.00	41.70	83.33	3.97	2600.00	4820.22

contd ...

1	2	3	4	5	6	7	8	9
22.	Panki	Uttar Pradesh	284.00	51.05	94.07	17.30	2324.00	3629.40
23.	Harduaganj(B)	Uttar Pradesh	210.00	34.38	81.74	36.37	2500.00	3772.90
24.	Harduaganj(C)	Uttar Pradesh	170.00	36.41	81.34	34.87	2500.00	3456.51
25.	Barauni	Bihar	145.00	25.79	75.00	33.14	2500.00	4262.99
26.	Durgapur Power Projects Ltd.	West Bengal	285.00	28.54	70.22	14.29	2365.00	3239.47

NOTE : Planned Utilization Rate = 1- Planned Outage Rate

Heat Rate (*Ex ante*) = Specific heat consumed by turbo-generator as designed for specific steam and pressure (e.g., conventional, reheating, double flow reheat regenerating cycle)

Heat Rate (*Ex post*) = Actual heat consumed by BTG sets.

SOURCE : Various issues of State Electricity Boards, and Central Electricity Authority (Reports)

planned utilization rate and the actual capacity utilization, and (ii) the actual heat rate and fuel-mix combinations in use are widely different from the technologically determined optima. The observed inadequacy in maintenance practices may explain these differences to an extent. However, there are reasons to believe that factors at the level of planning and execution can also have an effect on the observed pattern of behaviour.

1.5 THE PROBLEM FOR ANALYSIS

The analysis of the preceding sections indicated that there has been a shortage of power supply despite significant capacity expansion in thermal power generation. It is also generally agreed that there is a need to examine the factors responsible for the shortages and prepare a concrete program of action so as to avoid as much of the chronic load shedding (i.e., inability to satisfy the load at the bus-bar) as possible. A systematic analysis of this problem would be possible if we approach it from the following vantage point.

Part of the power shortage is due to the inefficiency of the operational decision procedures of the managers of the power plants. Every power plant has an optimum level of fuel choice, and consequently a heat rate, given the rate of utilization of the installed capacity. However, as observed in the previous sections, the actual choices do not appear to correspond to this. Hence, an attempt will have

to be made to identify the sources of inefficiency and assess their quantitative impact.

Planning for power plant availability may itself be a source of inefficiency. For, given a load duration curve and expected outages due to maintenance schedules, there would be an efficient utilization rate to which the system operation should be directed. This is generally a result of the cost factors, especially capital cost, implicit in the utilization of power plants at a predetermined rate. It is possible that the optimal plant availability is not planned for before directing operational decision procedures to it. Quite clearly, this dimension of inefficiency may have an additive impact[20] to the lower level deviation from optimality alluded to earlier.

Factors inherent in the plans for installed capacity, and capital equipment may themselves constrain the management in its attempt to make electrical energy available at the lowest cost. It is not possible to maintain the minimum cost per kWh even at peak operational efficiency so long as the initial choice of installed capacity and technology embodied in the capital structures are not optimal. Even this aspect of the problem requires a careful analysis.

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20. An increase in forced outage rate does not create a proportionate reduction in the available capacity and consequently rate of capacity utilization. Hence, the observed rate of capacity utilization should generally be higher than effective plant availability rate (i.e., plant availability-forced outage rate). For details, refer to Graver (1966), and Loose and Flaim (1980).

It, therefore, follows that, in general, the observed inefficiency in the operation of the thermal power plants may be due to one or more of the following three aspects :

(i) system inefficiency in choosing the capacity installed,

(ii) inefficient planning in the determination of the rate of capacity utilization, and

(iii) operational inefficiency resulting in high heat rates and inefficient fuel-mix.

Hence, there is a need to examine the extent to which each of these factors contributes to the observed inefficiencies. This would be a necessary first step for designing plant expansion as well as operational decisions so as to cater to the growing demands on the system.

Analytically, the following dimensions of power plant operations should be appropriately integrated to arrive at a framework of analysis.

(i) The output as well as the capital equipment of the power plants must be recognized as being multidimensional. Each of these dimensions has a differential impact on the cost structure.

(ii) There is a hierarchical decision process. The decisions at the level of planning the installed capacities and utilization to cater to a prescribed load duration curve are assigned to one group of decision makers. Planning for plant availability and ensuring that this level of

power generation is delivered at the bus-bars is the responsibility of a different level of hierarchy. The components of cost involved at the two different levels of decisions have differential impact on system costs. Hence, the decision variables within the purview of each level of management, their cost impact, and overall system efficiency will have to be defined appropriately.

(iii) There are technical, economic and managerial dimensions of choice[21] in power plant operation. Each of these has implications for the other and often in rather complex ways. The analytical methods should be capable of reflecting these inter-relationships succinctly.

(iv) Uncertainty has an essential role in determining the efficient performance of power plants. The load duration curve exhibits demand uncertainty. Similarly,

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21. Technical choice is restricted to BTG (Boiler Turbine Generators) units, e.g., heat rate, fuel-mix etc. Economic choice is based on minimum cost calculation, e.g., heat rate, fuel-mix, capacity utilization rate, planned utilization rate etc. Managerial choice implies co-ordination between technical and economic choice in a given hierarchical structure.

the pattern of forced and partial outages contains information regarding production uncertainty. A stochastic system is much more vulnerable to inefficiencies unless the decision process makes necessary adjustments for it. It is important to characterize these stochastic elements appropriately and identify their possible impacts on system efficiency.

The major contribution of the present study consists of the identification of appropriate dynamic cost functions which take cognizance of the above peculiarities of the power system. It would also be demonstrated that the method of analysis is capable of isolating the source and extent of inefficiency exhibited by the actual operation of the power generation system.

CHAPTER 2

ALTERNATIVE ANALYTICAL PROCEDURES

2.1 POWER PLANT ECONOMICS

Power plant design and operation are largely a matter of economics. In general, the average cost of a kWh of energy delivered at the bus-bar has four components - fuel, capital, operational labour and maintenance. Their respective shares in total cost are 49 percent, 39 percent, 7 percent, and 5 percent. These proportions vary considerably from one plant to another due to a variety of factors.

Consider the capital cost components to begin with. Given the installed capacity and the technology embodied therein, the capital costs[1] attributable to operating the plant over one unit of time depend on two factors. Firstly, an increase in the average availability of the plant increases the capital cost per unit of energy delivered. Secondly, any inefficiency in the use of the plant and its

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1. One engineering fact that is commonly related to the economic concept of scale economies is the 'two thirds rule'. This rule merely notes the mathematical fact that for most geometric shapes, surface area grows less rapidly, than volume. If output is closely related to the volume of a piece of equipment (e.g., a boiler, a turbo-generator) and fabrication cost is related to surface area (e.g., the amount of material required to construct the equipment) then the cost of equipment should increase less than proportionately with its volume.

inability to deliver the planned levels of output increase average capital costs further[2]. However, there have been improvements in design which enable better utilization of the higher temperatures and pressures upto ever increasing metallurgical limits. But the capital costs of new technology are higher. For, increasing operating temperatures and pressures create greater frictions and heat losses. The design of the generators which attempt to minimize these require more reliable engineering materials. The optimal choice of technology for a given design size involves a trade-off between capital cost and fuel efficiency.

The operating costs are also dependent upon the boiler design and other technological characteristics. In general, an efficient design with a higher capital cost results in a lowering of the unit operating costs. But, once again, the actual average cost may be

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2. There is a relationship between boiler design and fuel used which also has implications for capital costs. For, it is well-known that the adaption of a coal-fired plant to handle gas or oil is relatively inexpensive, but the adaption of a gas or oil-fired plant to handle coal is rather expensive. This is because a coal burning plant generally requires 10 percent to 15 percent more capital investments primarily in coal and ash handling equipments and more expensive boiler design. On the other hand, coal has a greater thermal efficiency and typically requires about 3 percent to 5 percent fewer Kcal per kWh than gas with oil occupying an intermediate position.

substantially higher than the minimum specified by the design structure. This occurs whenever inefficient operation results in abnormal outages of the plant.

To an extent, it is possible to maintain that the design of power plants[3] must take into consideration all these possibilities and to plan them in such a way as to provide a kwh of energy at the lowest possible average cost. But this is not always possible. Some inefficiency is inevitable given the stochastic nature of the power system in operation.

Various attempts have been made to examine the nature of power plant operations at the micro as well as the macro level. An attempt will be made in the present chapter to identify the available methods of approach and their relative usefulness for the analysis we envisage.

2.2 PRODUCTION FUNCTION APPROACH

In economic theory, a production function represents a relationship between the inputs and outputs of a production process. Generally, for a given technology embodied in the machines being installed, it would represent the maximum possible output from a given

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3. This would be taken to include the choice of technology as well as the installed capacity.

combination of inputs. The isoquant ABC, drawn for one kWh of energy in Figure 2.1, is a general description of technology and the production function.

At the planning stage, the choice of inputs would be such as to minimize the cost of production given the factor prices. In Figure 2.1, DE represents an iso-cost line and B the efficient input choice. This is only an *ex ante* choice. In the short-run, however, the capital stock is fixed. If S (or L) is the installed capacity then the point X (or Y) along the isoquant is the minimum cost choice of inputs. Hence, one of the sources of inefficiency arises from the fixity of the short-run capital stock in relation to the factor prices which prevail during the short-period.

Secondly, the choice of inputs B assumes that the operational management, which combines the capital and fuel inputs to deliver the output, is efficient. That is, they extract the maximum output that is in fact attainable. However, it appears plausible to postulate that this efficiency is not attained in practice. Under such conditions the one unit of output may be produced along the isoquant $A^*B^*C^*$. Even along this inefficient isoquant the actual choice of inputs may not be the cost minimizing B^* but only F^*.

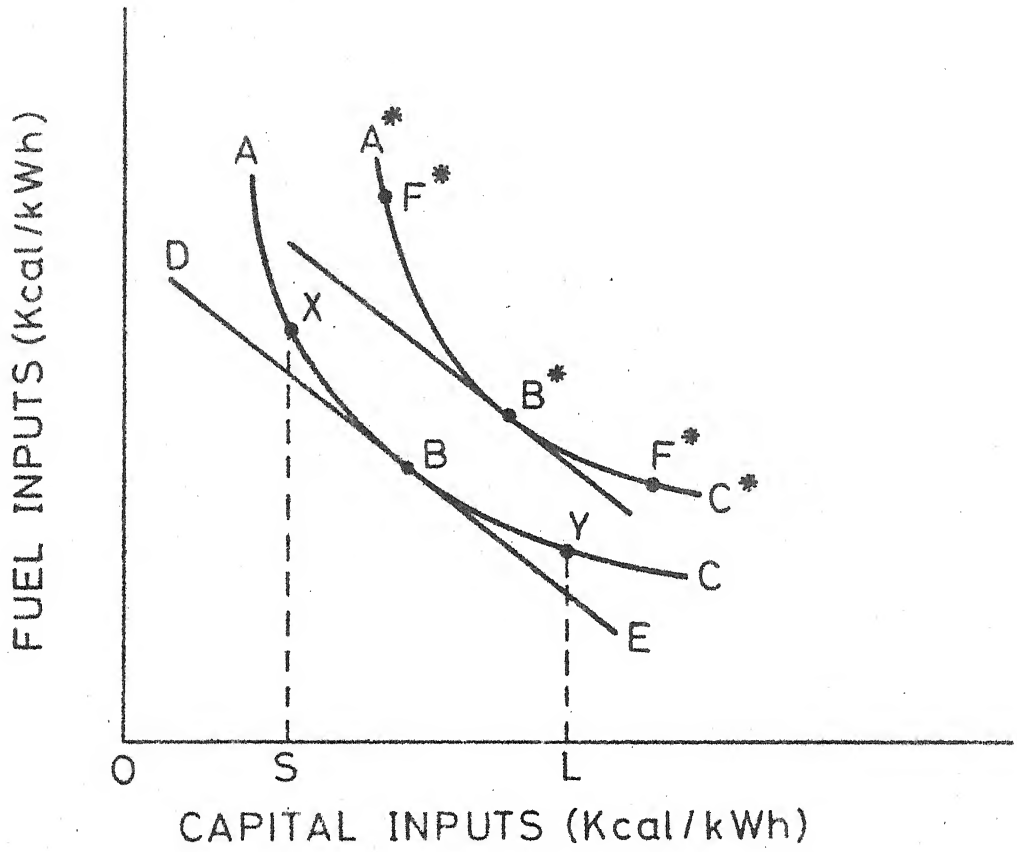

FIG-2·1 PRODUCTION FUNCTION FOR ELECTRIC POWER GENERATION

Hence, in order to isolate the inefficiency in the decision process , it would be necessary to identify the B or X in relation to F^*. Estimation procedures are available to accomplish this task.

However, the available observations would generally confound another problem. For, in most plants there are many units of different sizes which embody different production techniques. In such a context, the production functions and isoquants are expected to reflect the best practice technology. That is, they exclude those technologies which use more of one input and as much or more of all other inputs in order to produce a given quantity of output.

To illustrate the concept more concretely let us assume that in order to produce a given amount of electricity, we can use two different techniques using different combinations of fuel and capital. One technique, say the use of the steam turbine, permits the use of various combinations of fuel and capital in the production of one unit of electrical energy as indicated by the line ABC in Figure 2.2. The second, say the gas turbine, has an isoquant DBE, given these technological possibilities, the efficient input combinations, to produce one kWh of energy, are along the path DBC. This isoquant now provides an operational description of the production function .

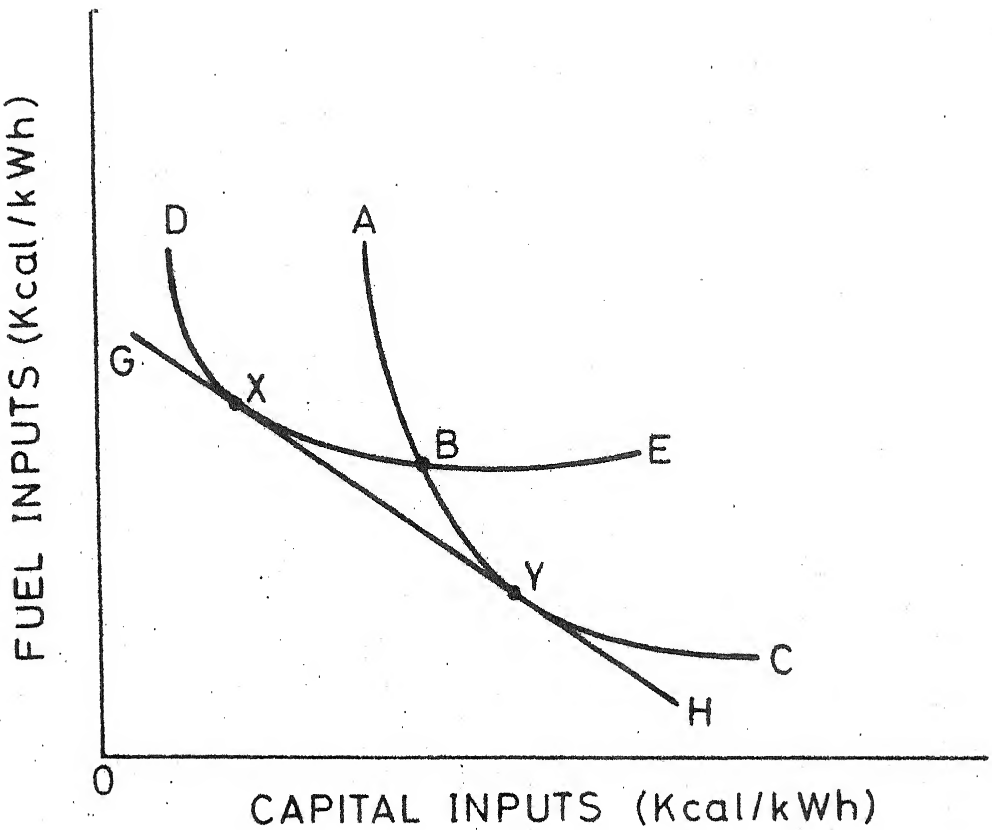

FIG.2·2 MANY TECHNOLOGIES IN ELECTRIC POWER GENERATION

Within the present set up, both technologies may be equally efficient at input combinations X and Y respectively. Even if one is superior to the other *ex ante*, it may be desirable to use both over the short-run. It would be difficult to illustrate this in a diagram. For, the capital cost considerations cannot be successfully reflected either by the iso-cost curves or the isoquants. One useful illustration is offered in Figure 2.3, where the reduction in the capital cost of the better technology is reflected in the flatter iso-cost curve beyond B^*.

Inefficiencies in decision making can also be identified. Quite clearly, the specifications using the production functions would be quite involved.

Consider the multidimensional nature of the output of the steam electric generating plants. It is well-known that different rates of instantaneous utilization over a specified time interval can deliver the same cumulative energy. All of them may require the same amount of inputs. But some of these combinations are feasible while the others are not. For, only a part of the demand generated at a point of time can be postponed to the next time point. The optimal time profile of generating a given amount of energy over a well-defined time interval is itself important. But the multi-output production function specifications have not been able to examine this aspect of efficiency of planning power plant operations.

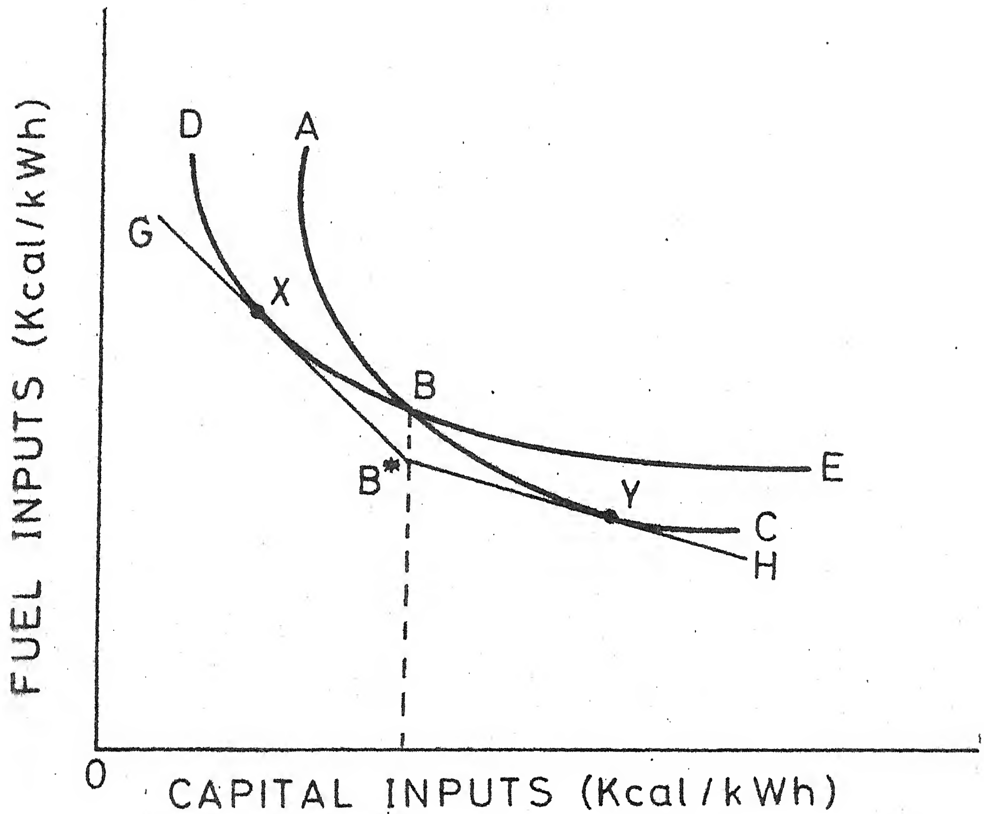

FIG. 2·3 TECHNICAL DIVERSITY AND CAPITAL COSTS IN ELECTRIC POWER GENERATION

The conventional production function approach, outlined so far, does not make any modifications for the stochastic nature of supply. In some earlier studies, the technical frontier, which represents an upper bound on output, was estimated by discarding observations which are not on it. No attempt was made to isolate the source of randomness.

In more recent studies, the notion of a stochastic production frontier is developed to account for such situations. In such specifications the output of each firm is bounded from above by a frontier that is stochastic in the sense that its replacement is allowed to vary randomly across plants. The inter-plant variations of the frontier are expected to capture the effects of exogenous shocks beyond the control of the management.

However, these approaches have not been able to examine the possibilities of overcapitalization, inappropriate planning of the use of installed capacity, and inefficient choices of fuel-mix.

On the whole, models developed from the production function framework fail to capture both the important characteristics of power generation, viz., the multidimensional nature of output and capital. This is a limitation inherent in the specification of multi-output production functions currently available in the literature.

2.3 INPUT DEMAND FUNCTION APPROACH

Consider a simple production function of the form

$$P = \text{power generated (kWh)}$$
$$= f_1(I,F)$$

where I = installed capacity, and F = fuels used.

In the previous section, we postulated that the management of a power plant chooses I and F to minimize the cost of producing a given P. This can be expressed in the following equivalent form

$$F = f_2(P,\ i/f)$$

where i = cost of using I per unit of time, and f = price per unit of fuel.

This may be called an input demand function and provides an equivalent approach to the specification of the production functions.

From Figure 2.4, it may be noted that for a given P there exists a marginal revenue product curve which provides the input demand curve. Given f, the optimal fuel choice is F (i.e., point A on the MRP curve). If there is inefficiency in the production process then the MRP would be along the curve X and the actual input choice, such as the point C, indicates inefficiency (Compare point C with efficient choice, point B on the MRP curve).

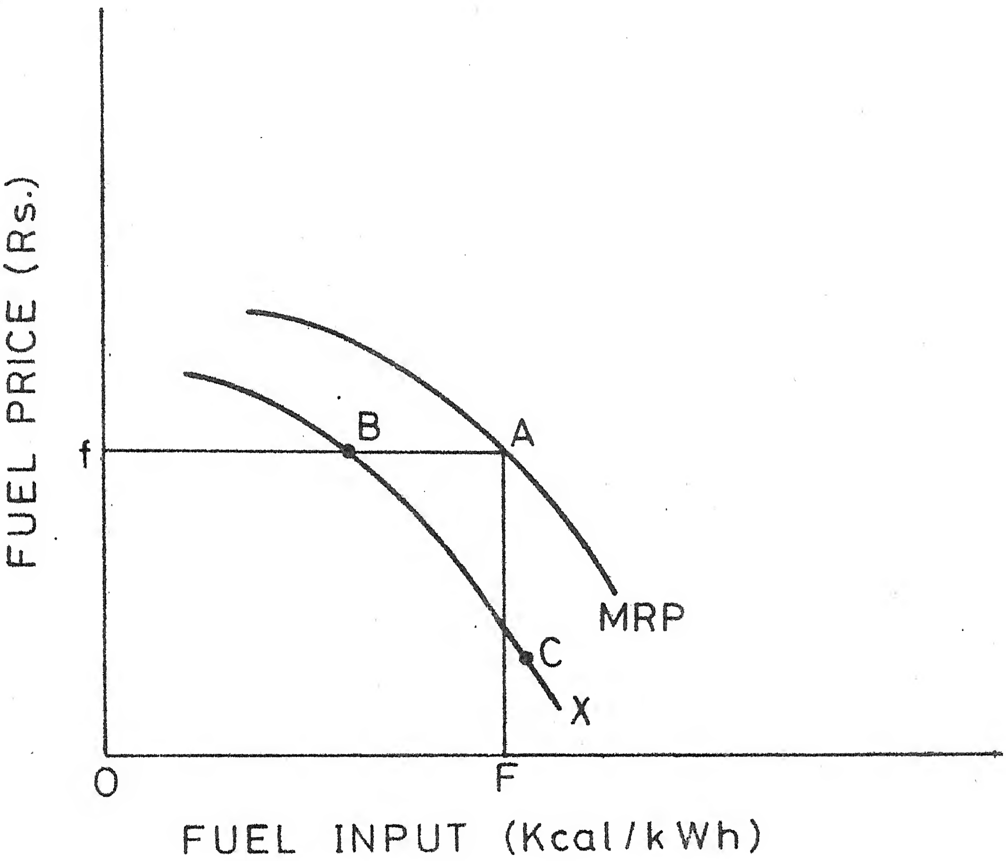

FIG.2.4 INPUT DEMAND FUNCTIONS IN ELECTRIC POWER GENERATION

In the context of power generation, it is necessary to account for the multiple output structure of the production process. For, the demand for inputs depends not only on the cumulative output generated over an interval of time but also on the patterns of instantaneous use. If the structure of the multi-output production function is well-defined then it would be possible to develop the corresponding input demand functions. It is well-known from Theil (1980) that there is a one-to-one correspondence between multi-output production and input demand functions. Hence, conceptually, this approach is equally elegant. However, the input demand function approach is subject to all the limitations inherent in the specification of multi-output production functions.

The existence of uncertainty distorts the smooth MRP functions and does not provide any useful method of defining the efficient use of resources. Consequently, it would not be possible to accurately develop a procedure to answer the questions at hand.

Though, in general, the input demand function approach is plausible, it is inferior to the production function approach from a different vantage point. For, referring back to Figure 2.4, observe that the MRP curves are drawn for a given P and cannot therefore provide us a method of examining the optimality of the choice of P itself. But this is an important problem which cannot be ignored.

On the whole, the input demand function approach is inferior both due to specification difficulties in a multi-output set up as well as its inability to distinguish between the various sources of inefficiency independently.

2.4 THE COST FUNCTION APPROACH

Given a production function of a single output, multi-input production process, and the usual postulate that the managers of the firm choose the inputs to minimize the cost of producing a given volume of output, there exists a unique cost function. This result is well-known and is commonly referred to as the Shephard's (1953) duality theorem. Consequently, in the simplest case, it is possible to approach the problem equivalently through a cost function.

The primary advantage of this approach consists of the fact that the variations in cost which arise due to changes in installed capacity, output, and factor proportions can be explicitly exhibited. Secondly, the cost function approach enables us to disentangle the sources of inefficiency systematically rather than in distinct isolated steps.

To illustrate this viewpoint, consider the AC curve of Figure 2.5 given the specification of the underlying technology. Given the installed capacity, we can conceptualize the optimal power output P at the minimum point on the

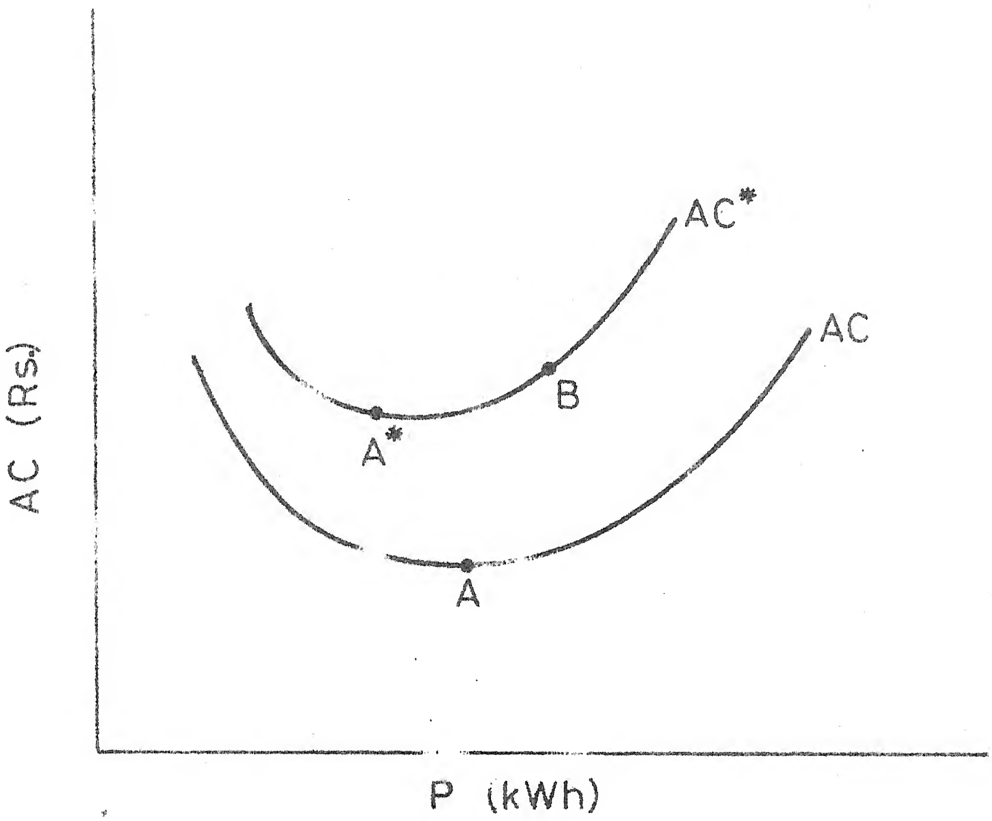

FIG. 2.5 ISOLATING INEFFICIENCY BY THE COST FUNCTION APPROACH IN ELECTRIC POWER GENERATION

AC curve (i.e., point A). If the choice of fuels and their use is not efficient it follows that the firm is operating inefficiently. The actual choice may be at a point such as B in comparison to cost minimizing solution to be A^*. This would signify an inefficiency in the plan for P as well as the inefficiency of fuel choice corresponding to that level of output, P. It is also apparent that the cost function approach readily enables us to identify the optimality of the choice of installed capacity.

Consider the efficiency of this method when confronted with a multi-output production process. It is well-known that there is no unique one-to-one correspondence between a class of production and cost functions in such a case. However, even when a production function cannot be specified, it is possible to specify cost functions for multi-output situations so as to examine every one of the questions posed in Chapter 1, Section 5.

Even the stochastic variations in costs, caused by unexpected events like forced outages, can be explicitly accounted for in the specification of the cost functions. To that extent, it would be feasible to identify the optimal changes in the decision processes as an adaptation to the exogenous disturbances. Consequently, it is also possible to specify the extent of inefficiency inherent in the inability or unwillingness to adapt to external environmental changes.

2.5 OTHER ALTERNATIVES

The mathematical programming approaches are quite popular in the literature. Primarily the flexibility they offer in handling multi-output, multi-input processes with the implied technical and institutional constraints is their advantage. However, they depend crucially on the appropriate specification of the production process. If, as we noted earlier, this specification has inherent disadvantages, they carry over to the programming formulations. Secondly, this method requires that the constraints on the decision processes should be spelled out explicitly. It is not at all clear if there is usable information regarding this aspect of the problem.

Hence, the cost function approach, which does not require such an explicit specification of constraints, may yet be the optimal procedure from the viewpoint of diagnosing the extent of inefficiency rather than all the components and sources of it. The best choice and the relevant factors to be included in the modelling may be far more clear if we critically examine the experiences of others in using these different approaches to the problem.

CHAPTER 3

EXPERIENCES WITH THE ALTERNATIVE APPROACHES

3.1 THE PERSPECTIVE

The various methodological approaches to the problem, as outlined in the previous chapter, have been utilized in empirical studies though in somewhat varying degrees. The analysis generally differs in emphasis as well as the approximations introduced to capture the essential aspects of the empirical situation. However, they should be examined with a view to

(i) identifying the important aspects of the problem to be modelled,

(ii) choosing the appropriate methodology,

(iii) evaluating the choice of functional forms and descriptions of the decision choices at work, and

(iv) recognizing the technical and behavioural limitations inherent in the use of any one of the modelling methods.

The primary purpose of the present Chapter is to examine the existing literature on the use and efficacy of the alternative methodologies that are available. In particular, we will endeavour to concentrate on the following overall aspects of the problem which we identified in Chapter 1, Section 5.

(i) There is a distinction between *ex ante* and *ex post* choices in the study of the production process of steam electric power generation. To what extent can this distinction be highlighted in each of the approaches?

(ii) The available data is almost invariably a reflection of the *ex post* consequences of choice. Would it be possible to disentangle the *ex ante* decisions from these?

(iii) To what extent is the multi-output nature of the production process accountable?

(iv) Do input choices account for the stochastic nature of the supply in steam electric power generation? Can the differences in decision choices be reflected equally elegantly by all the methods?

(v) Which of the alternative methods is more convenient from the viewpoint of quantifying the direction and extent of inefficiency?

Since our review is functional, we will not deal with all the available literature. We also emphasize the pertinent aspects of the studies we consider. Therefore, no claims of exhaustiveness are relevant.

3.2 PRODUCTION FUNCTION SPECIFICATIONS

The production function approach is advantageous in so far as it exhibits the available input alternatives for producing a given level of output. Generally, it is well-known

that there are well-defined substitution possibilities, such as insulation thickness for heat transfer, and pipe diameter for fluid flow. Even when the specification and estimation of the isoquants are confined to the most important process variables, it describes the available alternatives regarding input choices for a given level of power generation.

Empirical studies dealing with production functions for steam electric power generation identified three primary inputs: fuel, capital and labour[1]. The capital inputs take the form of boiler turbine generator (BTG) units with specific physical attributes such as steam condition, heat rate, size, etc. In principle, there is scope for substitution between all the factors when the process is in the blueprint selection stage (i.e., *ex ante*). This substitution may involve capital for fuel through the use of larger BTG units with higher thermal efficiencies, or additional stages of reheat and feedwater reheating. Alternatively, there may be different ways in which capital and labour might be substituted through control automation or outdoor plants. The first of these options reduces the need for operating labour

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1. In addition to these primary factors of production, there are also somewhat less important inputs such as cooling water. Minor fuels would receive adequate attention in subsequent analysis to the extent that they influence the decisions with respect to the major factors of production.

and the second might be considered capital-saving but requiring greater maintenance labour.

Once a plant's design characteristics are fixed in terms of a specific configuration of capital equipment, we refer to the technology as *ex post* and the scope for factor substitution is substantially reduced. However, there may be inter-fuel substitution in plants with multiple fuel capability or increased labour inputs in maintenance to improve thermal efficiency and thereby save fuel.

A few studies approached the problem of estimating production functions for steam electric power generation directly from the plant level observed operational choices.

Komiya (1962) studied the *ex ante* production functions for steam electric generating units as well as for more aggregate plant levels. The estimated production functions were of the Cobb-Douglas form

$$Q = A\, x_1^{\delta_1}\, x_2^{\delta_2}\, x_3^{\delta_3}\, n^{\delta_4}$$

where Q is the rated capacity of a plant's generating units in MW, x_1 is the fuel input per generating unit when operated at full capacity, measured in BTU per hour, x_2 is the capital cost of equipment per generating unit, x_3 is the average number of employees per year per generating unit

and n is the number of generating units in the plant and δ_i ($i = 1, \ldots, 4$) are the input elasticities[2].

Contrary to expectations, Komiya's measure of output is the capacity level of output rather than the actual or observed rates. Secondly, the output measure used is a reflection of the instantaneous rate of usage rather than cumulative generation of energy over an interval of time. Further, the fuel consumption was adjusted to full capacity in proportion to the observed rate at the level of operation. However, the engineering literature on steam electric power generation established categorically that the fuel consumption per unit of output bears a non-linear relationship to the capacity utilization rate of the plant. Thus, the proposed adjustment appears to be inaccurate. In addition, it assumes that there is no inherent inefficiency in the choice and management of inputs. As such, this approach and Komiya's findings are not useful for the empirical purpose of the present study.

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2. The cost of land and structures were excluded from the measure of capital services on the ground that these two components varied considerably with the type of plant built and the number of generating units. An industry level index of equipment cost was used to deflate the capital cost.

Cootner and Löf (1965)[3] made an attempt to specify an *ex ante* production function for thermal power generation from engineering principles. It would be convenient to view it as a two-stage process. Let temperature and pressure be considered as factors of production at the first stage where thermal efficiency is established by choosing an appropriate combination of inputs. A production function for thermal efficiency, in terms of these factors, can be written as

$$H = h(T,P)$$

where H is thermal efficiency, T is temperature, and P is pressure.

The number of possible isoquants rises very sharply with each possible modification in initial design. For instance, if there are p possible reheats and q possible stages of feedwater heating, there will be pq possible isoquants for each level of thermal efficiency. Conceptually, at any rate, the actual shape of the efficient production frontier can be estimated from these results.

The heat rate so defined must be available to the electric power generation process. The available heat

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3. Further detailed studies were reported in Vries, Dijk and Nieuwlaar (1981) and the references cited therein.

from given fuel combinations is usually called exergy. The second stage production function is now conceptualized as the choice between capital and exergy inputs to deliver a pre-defined name-plate capacity. In particular, it has been established from thermodynamic and other engineering considerations that

$$K = \text{capital stock} = \text{Constant } \varphi^{a}$$

where φ is the measure of exergy and $-1 \leq a < 0$. In this equation, φ depends inversely on H, the thermal efficiency established earlier[4].

However, it appears that the function h cannot be independent of the design of capital structures. Hence, it may be much more meaningful to specify the choices between all the inputs simultaneously. The only operational difficulty would be in arriving at the most appropriate functional form for estimation.

Therefore, this study, though elegant in engineering details does not contain sufficiently useful information.

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4. Cootner and Löf (1965) and other related studies maintain that there is a minimal exergy requirement for a given technology and that substitution possibilities exist only beyond that point. The above (K,φ) - relationship would have to be modified accordingly to make it operationally relevant.

First of all, the measure of output is not directly related to the KWh of energy delivered at the bus-bar. Secondly, the concepts of temperature and pressure adopted by the study do not result in any unambiguous notion of prices for inputs from the viewpoint of measurement and optimal choice. Thus, even within the limited specification it is not possible to define efficient fuel use let alone examine the optimality of the choice of other factors of production.

In contrast, Stewart (1979) models an electricity producing plant's ex ante choice of technology by assuming that the output is best described by a load increment composed of an instantaneous rate and a time duration. The cost of capital equipment, in this model, is dependent on the size and fuel efficiency of the plant. It has been assumed that electric power is produced by combining fuel and equipment and that the range of available equipment can be defined by the size and fuel requirements of the equipments. It has also been assumed that fuel requirement of a given piece of equipment is constant and fixed. Thus, once the unit is installed, neither the size of the unit, nor its fuel requirements can be altered. The production technology for a plant of given characteristics is defined by a fixed coefficient production function :

$$Q = \min \left[\frac{F}{\alpha_0}, 8760\ K_o\right]$$

where Q is the yearly KWh demand, 8760 is hours per year, F is BTU's of fuel per year, α_o is the plant's heat rate (BTU's/kWh), and K_o is the plant capacity (KW's).

This approach views plant capacity and fuels as limitational factors which can only be used in fixed proportions. There is no allowance for less than full utilization of capacity, changes in thermal efficiency and fuel use with the level of electricity generation, and substitution among fuels at a given level of capacity use. Fundamentally, therefore, such an approach cannot at all provide a conceptual basis for the problems we seek to examine.

Aigner et al. (1977), and Schmidt and Lovell (1979, 1980) estimated stochastic production frontiers using data on steam electric generating plants. The plant's power generation technology is characterized by a production function of the form

$$Y = a \prod_{i=1}^{n} x_i^{\alpha_i} e^{\varepsilon}$$

where Y is the output, the x_i's are the inputs to the production process, ε is a random disturbance, and a and the α_i's are parameters to be estimated. The disturbance is assumed to be of the form

$$\varepsilon = v - u$$

Here v is distributed as $N(o,\sigma_v^2)$ and captures random variation in output due to factors outside the control of the plant. On the other hand, u is a non-positive disturbance which is assumed to be half-normal $N(o,\sigma_u^2)$. The production function is rewritten as

$$\ln Y = A + \sum_{i=1}^{n} \alpha_i \ln x_i + (v-u)$$

where A = ln a.

Now, ln Y is bounded from above by the stochastic production frontier

$$\ln Y = A + \sum_{i=1}^{n} \alpha_i \ln x_i + v$$

In their empirical estimation, the measure of output is electricity generated (10^6 KWh) in the first year of operation. Capital is the actual cost of the plant. Fuel is the actual consumption (10^6 BTU) of fuel (coal, oil or gas) in the first year of operation. Labour is the design labour force measured in total employee manhours (total employees X2000).

The study found that inefficiency averaged 10.1 percent over the sample. System inefficiency, in the form of excessively high capital/fuel and capital/labour ratios, led to additional inefficiency of the order of 9.2 percent.

In addition to some of the drawbacks of the earlier studies, this approach lacks a behavioural basis to identify the causes of the different kinds of inefficiency which are indicated. It is also unrealistic to assume that the management does not make any adjustment in its decisions corresponding to observed and/or anticipated exogenous disturbances. Similarly, inefficiency is created not merely due to non-optimal factor proportions but also due to inappropriate planning for the output levels given the installed capacity. The study does not provide any analysis of these aspects of the problem which require explicit attention.

On the whole, it may be claimed that the production function approach appears inefficient with respect to the following dimensions :

(i) Choice of output measures exhibiting the multidimensional character of the production process,

(ii) incorporating decisions regarding the utilization of installed capacity,

(iii) technical and economic choices of fuel use and the extent of *ex ante* and *ex post* substitution available[5], and

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5. In particular, recall that none of the studies described in this section was able to specify the distinction between the *ex ante* and *ex post* production choices let alone estimate them.

(iv) incorporating the behavioural responses of management to exogenous disturbances like forced outages of plant.

Consequently, this approach would not be effective in providing useful answers to the questions we seek to examine.

3.3 INPUT DEMAND FUNCTION APPROACH

Given a production function, the input demand models can be derived from either cost minimizing or profit maximizing behaviour and permit indirect evaluation of the production technology. Even when the production technology is not well-defined, it is possible to specify the input demand functions independently and make an attempt to examine the efficiency of input choices. Hence, unlike the production function approach the input demand models may be capable of analyzing the *ex post* input choices effectively. Some studies approached the problem of characterizing the production function for steam electric power generation by estimating the input demand functions. The following empirical experiences are representative of this method of analysis[6].

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6. Further detailed studies are reported in Seitz (1971), and Cowing and Smith (1978) and the references cited therein.

Barzel (1963, 1964) specified log-linear input demand functions for each of the three inputs : fuel, labour and capital. The fuel and labour equations included plant size measured in terms of name-plate capacity, measures of both the anticipated and the actual average rate of capacity utilization (i.e., the ratio of the actual to the anticipated or designed plant factor), measures of both anticipated and actual relative prices of fuel and labour, the age of plant (i.e., accumulated number of operating hours) and a set of dummy variables indexing the year of plant installation. The inclusion of anticipated and actual variables for both the rate of capacity utilization and the relative prices of fuel and labour allowed the *ex ante* effect across common vintage plants and the *ex post* effect across time to be separately evaluated. The capital demand equation included plant size, dummy variables for indexing the year of installation, the anticipated rate of capacity utilization, and the relevant factor prices. Fuel input per year was measured in actual BTU's while labour inputs were measured in terms of average number of employees per plant per year, and capital input as the total undeflated value of the plant.

Barzel found significant *ex ante* scale effects in the fuel demand equation for both plant size and the expected plant factor. The results also indicated a significant

ex post scale effect in the elasticity of fuel input with respect to the ratio of actual to expected output. The results suggested that the *ex ante* scale effects for labour inputs were appreciably greater than those for fuel. There was substantial variation across plants of different sizes. The *ex post* scale effects, i.e., variations in labour inputs due to variations in *ex post* capacity utilization, were not significantly different from zero. However, the relative price effects were significant.

The capital input equations were based on a cost measure rather than a physical quantity measure. The effect of plant size and expected rate of capacity utilization on capital cost were significant. The study found evidence of substantial *ex ante* input substitution in the estimated elasticities of plant cost with respect to the relative prices of labour and fuel (to capital).

However, the price of capital was not included in any of the three demand functions due to problems in defining and measuring it. This omission is a potentially serious source of bias if the coefficient for the excluded variable is reasonably large and if the price of capital is correlated with any of the included variables.

Cowing (1974) developed an engineering process model with three inputs : capital in terms of BTG units, flow-through inputs in the form of fuel, and control and

maintenance inputs in the form of labour with some associated capital. This method focuses attention on the physical nature of capital like capacity, efficiency, flexibility[7] and so on.

Fuel inputs were assumed to be related to the thermal efficiency of the BTG units. Thus, the *ex ante* input demand functions for capacity and efficiency were derived in terms of expected relative prices for fuel and capital and an index for embodied technical change. A log-linear specification was used for each as

$$\ln E = K_1 + a \ln \rho_e + bV$$

$$\ln Z = K_2 + c \ln \rho_e + dV$$

where E is the optimal thermal efficiency, Z is the optimal size of the selected machine, ρ_e is the ratio of the expected present value of fuel prices over the expected life of the machine and the price of the machine, and V is an index of technical change.

The size was measured as the maximum rated capacity of the machine in MW, while the thermal efficiency was measured in terms of the designed heat rate. The expected fuel price was measured by the average fuel price over the first two years of plant operation. The internal rate was measured by the nominal interest rate on the firm's bonds

7. The concept of flexibility, first introduced by Stigler (1939), concerns a design feature of technology which would (at the single plant level) permit operation over a range of outputs without appreciable increases in unit costs. This contrasts with the more conventional view that a plant would be designed to operate at a single level of output.

issued just prior to plant installation. The Handy Whitman index (Cf. Whitman and North (1953)) of steam electric plant construction cost was used as an index of capital (stock) prices. Vintage was measured by the year of installation.

The results indicated that fuel efficiency was sensitive to the expected relative price ratio of fuel and capital while the machine size was not. The scale-augmenting technical change indicated that the larger machines were more efficient with each new vintage.

We notice that a correct formulation of the cost minimization procedure for plants in the steam electric power generation, taking fixed capital into account, leads to factor demand functions which depend on the exogenous outputs of the planning horizon. The estimation procedure as well as the forms of the functions involved are very different from those implied by the assumption of one period cost minimization in these studies. Moreover, Cowing's study does not recognize that a machine may not operate at full capacity in each hour of generation and when it operates but not connected to the load, instantaneous output is zero. There is no consideration of machine-mix of plants, nor of the degree of capacity utilization of plants.

McFadden's (1964,1978) study sought to develop a general analytical framework capable of estimating parameters of the

production technology. The basic approach was to derive general classes of <u>ex ante</u> input demand and cost functions given a neoclassical technology with three inputs; fuel, labour and capital. Plant capacity was measured as the net continuous plant capability (of production) in MW when not limited by condenser water, and output was measured as the annual net generation in kWh. The plant factor (mistakenly referred to as the load factor) was defined as the ratio of output to capacity. Labour was measured as the average annual number of employees. The wage rate was calculated by dividing total plant labour costs by labour. Maintenance labour costs were estimated and included in total labour costs. The plant capital cost was measured as the net value of the plant after depreciation. Total plant cost in value added terms (i.e., not including fuel costs) was expressed by the sum of total plant production expenses and imputed plant 'economic' capital costs.

The results suggested that fuel was not substitutable for either capital or labour. There were indications of (i) increasing returns to plant scale with respect to fuel consumption, and (ii) the production function being non-homothetic with a bias towards higher capital-labour ratios as plant capacity increased. The estimates also suggested that labour was linearly related to output <u>ex post</u> while on an

ex ante basis there were increasing returns to scale with respect to capacity.

Dhrymes and Kurz (1964) analyzed the *ex ante* production technology of electricity generation at the plant level using two alternative specifications :

(i) a neoclassical model allowing for substitution among three inputs; fuel, labour and capital, and

(ii) a limited substitution model which permitted only fuel capital substitution.

The econometric model consisted of a set of input demand functions derived from a generalized non-homogeneous CES production function

$$Q = \min[g(L), (\alpha_F F^{\beta_F} + \alpha_K K^{\beta_K})^{1/r}]$$

where g(L) is the minimum amount of (non-substitutable) labour required to produce Q units of output; F,K and L are fuel, capital and labour input respectively, per unit of time period.

Unfortunately, it was not possible to analytically derive each of the three required input demand functions explicitly in terms of output and relative input prices. Thus, a two-stage technique was used. In the first stage, a log-linear demand for capital function was estimated by using Taylor-series expansion in output and relative prices.

The resulting estimates of $\ln K$, $\ln K^*$ were then used in the second stage to estimate the fuel input demand function

$$\ln F = \frac{1}{\beta_F - 1} \ln \frac{\alpha_K \beta_K}{\alpha_F \beta_F} + \frac{1}{\beta_F - 1} \ln \frac{p_F}{p_K} + \frac{\beta_K - 1}{\beta_F - 1} \ln K^*$$

$$\text{where } \ln K^* = \hat{b}_o + \hat{b}_1 \ln \frac{p_K}{p_F} + \hat{b}_2 \ln Q$$

Output, labour, fuel, and capital were measured as kwh of net generation, average annual number of employees, actual total BTU's, and adjusted MWh of capital serive services respectively. The capital service variable was based upon name-plate capacity adjusted by the percentage of time during the year that each of the units in a plant was either connected to load or 'hot but not connected to load'. The price of fuel in dollars per BTU was calculated by dividing total annual fuel expenditure by total fuel usage in BTU's. The rental price of capital services in dollars per MWh has been computed using a residual method by which non-capital costs were subtracted from the estimated value of the plant output and the resulting estimate of capital costs was divided by the measure of capital input to yield an estimated return on capital. The maintenance costs at the plant level were included within the definition of capital costs.

The results favoured the adoption of the limited substitution model with labour input specified to be a logarithmic function of output and dummy variables to allow for regional differences due to type of plant construction, i.e., outdoor versus conventional construction. The estimates indicated the general tendency for the degree of returns to scale to decline with increases in size.

Galatin's (1968) specification of the *ex post* technology assumed that fuel was the only variable input. The fuel requirements of a power plant will be affected by the time pattern of generation over an year. However, the data on input usage relate to annual flows and do not allow the effects of instantaneous use patterns to be separated. Accordingly, Galatin assumed that plants will minimize the costs of producing an exogenously given output produced in identical BTG units in the plant. This framework, given the assumption regarding the inability to substitute labour for fuel, implies that power will be generated by using each unit to its capacity until the load is covered. Thus, an *ex post* fuel requirement function can be distinguished from a derived demand function for fuel, since Galatin's assumptions imply that cost minimization will affect only the choice procedure in operating the units within a plant.

Unfortunately, the model assumed that the BTG units, within a plant, were the same in terms of their fuel use and cost characteristics. While the control of vintage effects took account of the potential for unit operating cost differences across units, it did not allow for substitution among them. It is noticed that fuel price changes may have an impact on different types of units operating with different fuels. Hence, the estimated fuel requirement equations may not be consistent with the outcomes expected from cost minimizing behaviour.

To delineate the instantaneous nature of choices within a plant, the rated capacity was adjusted using the data reported on the hours operated 'hot but not connected to load' in defining the plant factor[8]. The estimated fuel requirement function is

$$a_F = \alpha(l^*)^{-1} + \beta R_n^{-1} + \gamma$$

where a_F is the annual fuel input per kilowatt hour (kWh) of output per machine, l^* is the instantaneous rate of capacity utilization (i.e., adjusted by hours operated 'hot but not connected to load') and R_n is the average capacity per machine in megawatts (MW's).

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8. Plant factor in Galatin's terminology is equivalent to rate of capacity utilization in our study.

The estimated results indicated that with a given vintage machine, the fuel requirements per unit of output decreased over the full range of capacity.

Galatin's formulation of capital cost and labour requirement functions contrasted rather significantly with those of the fuel input equation. Both of them are <u>ad hoc</u> specifications. They cannot be developed from any well-defined characteristics of the steam generating technology. The capital equation appears to reflect the influence of demand and supply factors in the market for generating units, rather than the individual influence of the production technology.

It is evident from the foregoing presentation that the specification of the input demand functions has been severely limited due to the following reasons :

(i) The measures of output do not correspond to the observed magnitudes. Consequently, even the extent of aggregate inefficiency cannot be conceptualized.

(ii) The inadequacy of production function specifications render the specifications of the input demand functions ambiguous.

(iii) There are technological restrictions on the input demand choice which have not been appropriately reflected in the specifications. There is no <u>a priori</u> method of ascertaining the extent of bias in estimation resulting from these inadequate specifications.

(iv) It appears that there are fundamental differences in the specification of the *ex ante* and *ex post* factor choices. Neither the production function approach nor the method of estimating the input demand functions has been able to identify or capture the essential difference such choices entail.

(v) There has been no attempt at specifying or estimating the changes in the input choices which would be warranted when the management is confronted with supply uncertainty. As remarked in the earlier section, this is one aspect of the problem which did not receive any meaningful analytical consideration.

3.4 ESTIMATION OF COST FUNCTIONS

The classic specification of the Shephard's (1953,1970) duality theorem asserts that under certain conditions there exists a one-to-one correspondence between the production and cost functions. But we noted that (i) the specification of multi-output production functions is as yet inadequate, and (ii) even the specification of the substitution possibilities in the presence of stochastic supply procedures is unsatisfactory.

Estimates of cost functions, based on such duality relationships are inadequate from both these points of view. Recent attempts to extend the production function specification by utilizing the translog production functions gave rise to a

somewhat different set of problems. For, the translog cost function is not a dual of the translog production function. But the translog cost functions have the advantage of reflecting some of the essential non-linearities which would not be taken up by the more conventional specifications.

Certain additional features of the production process, such as the multi-output nature, were included in the cost function in an _ad hoc_ manner so as to obtain at least a first-order workable approximation. Nevertheless, these specifications have not been generalized sufficiently to capture the essential intricacies posed by the problems which we seek to examine. It is, as yet, rather difficult to see how these specifications can capture the essential differences between the _ex ante_ and _ex post_ cost functions.

Very sporadic attempts have been made to examine the effect of production uncertainty on the cost structure of the steam electric power plants. We shall briefly outline some of these studies in order to highlight the general approach adopted in the literature.[9]

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9. By and large, the emphasis throughout this section would be on representative studies and the essential aspects of them in so far as they are pertinent to the present study.

One of the earliest studies on the costs of steam electric power generation is that of Nordin (1947). The fuel cost equation was specified in the form

$$Y = a+bX+cX^2$$

where Y is total fuel cost for an eight-hour period and X is the eight-hour total output as the percentage of capacity. The instantaneous nature of the production process in terms of fuel input and the fact that the plant can operate at different degrees of capacity at each instant of time are embodied in this specification.

Johnston (1952 , 1960) estimated both the long-run and short-run cost functions for a sample of steam electric power plants. The cost variable roughly represents the variable cost. A total variable cost curve of the form

$$Y = a+bX+cX^2+dT,$$

where T is total deflated working expenses, X is annual output, and T is time in years, was estimated. The introduction of T was meant to explain the combined effects of depreciation, changes in management and production techniques, and so on. The short period results indicated a linear total cost function with constant average variable cost (AVC) and marginal cost (MC) curves. The addition of the total fixed cost to the total variable cost simply alters the position of the estimated cost curve.

The study of Lomax (1952) recognized that the pattern of capacity utilization of a plant may produce differences in unit costs of operation even within a plant of given installed capacity. Accordingly, the load factor was introduced in the specification of the cost function along with the installed capacity. The results indicate that, for a given load pattern, unit costs fall as the size of the plant increases. Similarly, given the size of the plant, unit costs fall as the load factor increases. This study, therefore, provides the earliest evidence of the necessity to introduce a multi-output specification.

Several other empirical studies of electricity cost are of this nature. Typical among these are McNulty (1956), Iulo (1961), Olson (1970), Fishelson (1976), and Meyer (1975). These studies postulated that the cost functions are usually simple polynomials in output.

Somewhat more conventional studies take into account

both the capital costs and operating expenses[10]. Such studies also often depend on conventional cost theory based on duality theorem. The foremost example of this nature is work of Nerlove (1963). In this study, the long-run total cost function was represented by a reduced form equation of the form

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10. Ling (1964) combined engineering information and economic theory to obtain cost functions for steam electric power generating systems in the following steps :

(i) Secular trends in steam conditions, e.g., pressure and temperature, and maximum installed capacity of turbines, are combined with engineering principles to derive a relationship between the plant heat rate and the unit scale.

(ii) Annual costs of generation of the system of size 2500 MW with a fixed machine-mix are calculated for varying degrees of capacity utilization. At various system sizes between 2500 MW and 13700 MW, annual costs of generation were computed for several system load factors as they were for the static model.

(iii) A Cobb-Douglas function was fitted but the following form provided better results :

$$C_a = kS^n \eta^{m+p \ln n}$$

where C_a is the annual average generating cost per kWh, η is the system load factor, and S is the system installed capacity in MW. The importance of economies of scale is indicated by the value of n, which shows that, for any given system load factor, the average generating costs decrease as the size of the system increases. Usually, such studies cannot offer any information regarding the actual operation of the power plants. By their nature they deal with technically optimum possibilities alone.

$$\ln C = \ln k + \frac{1}{r} \ln Y + \frac{a_1}{r} \ln p_1 + \frac{a_2}{r} \ln p_2 + \frac{a_3}{r} \ln p_3 + \ln v$$

where C is the long-run total cost, p_1, p_2 and p_3 are prices of labour, capital and fuel input respectively, Y is the output in KWh of generation, a_i's are parameters to be estimated, and

$$r = a_1+a_2+a_3$$

$$v = u^{-1/r}$$

$$k = r(a_o a_1^{a_1} \ a_2^{a_2} \ a_3^{a_3} \ )^{-1/r}$$

where u is a residual which is said to express neutral variations among firms.

It should be noted that this is a specification of the *ex ante* long-run cost function. It cannot provide any useful information about the short-run cost curves and consequently the *ex post* substitution possibilities among fuels and other inputs.

Christensen and Greene (1976) replicated the original Nerlove analysis by using the translog cost function. The translog is one of a group of generalized functional forms which places no *a priori* restrictions on the substitution elasticities. Since there are three inputs, the translog cost function is specified as follows :

$$\ln C = \ln \alpha_o + \ln Y + \sum_{i=1}^{3} \alpha_i \ln R_i + \tfrac{1}{2} \sum_{i=1}^{3} \sum_{j=1}^{3} \beta_{ij} \ln R_i \ln R_j$$

where C is total cost, Y is output, and R_i refers to the three input prices. Implicit in the coefficient for output is the assumption of constant returns to scale which can be relaxed. From the nature of the cost function, it is apparent that the translog offers a second-order local approximation to the non-linearity of the cost function. Several recent studies utilized the translog approach and improved empirical estimation somewhat. Prominent among these studies are Hudson and Jorgenson (1974), and Berndt and Wood (1975). The only major advantage of these specifications, from the vantage point of our present study, is their ability to introduce certain essential non-linearity.

Stewart (1979) used a fundamental modification of the translog specification to estimate cost functions of the form

$$\ln P_K = A+\gamma_\alpha \ln(\alpha-\bar{\alpha}) + \gamma_{\alpha\alpha}(\ln(\alpha-\bar{\alpha}))^2 + \gamma_K \ln(K)$$

$$+ \gamma_{KK}(\ln(K))^2+\gamma_{\alpha K}\ln(K)\ln(\alpha-\bar{\alpha}) + \sum_i \gamma_i X_i + u$$

where P_k is the dollar cost per KW of the generating unit (building excluded), α is the average heat rate of the unit (BTU's/kWh), $\bar{\alpha}$ is the asymptotic heat rate (6000 BTU/kWh), K is the capacity of the unit (KW), X_i's are shift variables, and u is a random error term.

The shift variables were included to account for

(i) the possible differences in labour or transportation costs in different regions, and

(ii) the number of units in a given plant.

The regression results indicated that (i) plant cost declines at a decreasing rate as heat rate increases, (ii) unit size has a relatively small impact on the cost of equipment, and (iii) the sign of the interactive term between heat rate and unit size is positive for gas turbine plants and negative for steam plants, i.e., it becomes more expensive at the margin to achieve incremental fuel efficiency in gas turbine plants as unit size increases and less expensive in the case of steam power plants.

The study estimated the costs of equipment function for a sample of plants and used the results to simulate the *ex ante* average cost curve over a grid of load increments which consist of an instantaneous rate and a time duration.

The simulation results can be summarized briefly.

(i) Given a plant utilization rate, the average costs decrease with unit size only for gas turbine units. However, costs increase with unit size for steam plants over the entire range. This is due to the effect of unit size on equipment cost. It is noted that the effect of unit size on average cost is quite small.

(ii) average costs decline for all unit sizes as the utilization rate is increased over the entire range.

Thus, Stewart emphasized the difficulty in arriving at the shape of the average cost curve of electric power generation in terms of cumulative output. For, one plant can exhibit double the kWh of output of another if (i) its capacity is twice as large and its utilization rate the same, (ii) its utilization rate is twice as large and capacity the same, or (iii) an appropriate combination of the two. However, the correct choice of an aggregate variable is in doubt. Introducing both the dimensions separately is imperative.

The study also compared (i) the observed heat rates of the plants with the cost minimizing heat rates predicted by the model, and (ii) the observed average costs with the minimum average costs predicted by the model. The results show (i) a downward bias of predicted heat rate and average cost, and (ii) the main source of cost reduction which stems from increases in the plant utilization rate and the ability of plants with higher utilization rates to spread capital expenses over a greater volume of output.

Fuss (1978) and Fuss and McFadden (1978), offer a direct test of certain hypotheses related to differences between the substitution possibilities in the <u>ex ante</u> and <u>ex post</u> production technologies. The model casts the

ex ante technology within a cost function specification.

The *ex post* cost function, a variant of the specification of Diewert (1971), is given by

$$C = \sum_{i=1}^{4} b_{ii}\, p_i\, h_i(Y) + \sum_i \sum_j b_{ij}\, p_i^{\frac{1}{2}}\, p_j^{\frac{1}{2}}\, h(Y)$$

where p_i's are observed input prices, $h(Y)$ is a function of output Y and the b_{ij}'s are *ex post* parameters of the production technology which are also related to the *ex ante* technology[11]. The four factors of production taken into account are : structures, capital equipment, fuel, and labour.

The primary result of the statistical analysis was the acceptance of a model allowing input substitution *ex ante* and fixed proportions *ex post*. (All four factors were assumed variable in the planning period, while structures and equipment were assumed to be fixed *ex post*). However, the essential differences between the *ex ante* and *ex post* cost function have not been examined in a convincing manner.

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11. The relationship between the b_{ij}'s and the *ex ante* technology is assumed to reflect *ex ante* minimization of the expected present value of the plant at the time of its selection.

Huettner and Landon (1973, 1978) estimated a cost function of the form

$$C = a_o - a_1K + a_2K^2 - a_3u + a_4u^2 + \sum_{i=5}^{n} a_iP_i + \sum_{j=1}^{m} b_jD_j$$

where K is peak capacity, u is the rate of utilization of peak capacity, pi are input prices, D_j's are dummy variables, and a_i's and b_j's are parameters to be estimated.

Here the output, Q = KU, does not appear in the cost function because peak capacity and the pattern of annual demand relative to peak capacity are the factors determining scale and costs. The study does not specify any production function but makes some observations on the duality relationship that is presumed to exist. The operating and fixed costs are separated and the fixed costs are expressed in terms of $/KW of capacity instead of $/KWh to examine scale effects on fixed costs. Thus, no assumptions are needed about economic life versus plant size and the particular method of depreciation to be used.

The estimated results showed that the short-run average cost curves are downward sloping for production costs, upward sloping for transmission costs, and inverted u-shaped for distribution costs.

Schmidt and Lovell (1979, 1980) estimated a cost function of the form

$$\ln c = K + \frac{1}{r} \ln Y + \sum_{i=1}^{n} \frac{\alpha_i}{r} \ln pi - \frac{1}{r} (v-u)$$

where $K = \ln[\sum_{i=1}^{n} k_i] = \ln r - \frac{1}{r} A - \frac{1}{r} \ln[\prod_{i=1}^{n} \alpha_i^{\alpha_i}]$,

Y is the output, pi's are the prices of inputs,

$r = \sum_{i=1}^{n} \alpha_i$ = returns to scale, $A = \ln a$,

$k_i = \alpha_i[a \prod_{i=1}^{n} \alpha_i^{\alpha_i}]^{-1/r}$, a and α_i's are the parameters to be estimated. v is distributed as $N(o,\sigma_v^2)$ and u is assumed to be half-normal, $N(o,\sigma_u^2)$.

It may now be noted that ln c is bounded from below by the stochastic cost frontier

$$K + \frac{1}{r} \ln Y + \sum_{i=1}^{n} \frac{\alpha_i}{r} \ln pi - \frac{1}{r} v$$

which represents the minimum possible cost of producing output Y with prices pi's. The term $(1/r)u$ represents the percentage by which actual cost exceeds the minimum attainable along the efficient cost frontier.

In the presence of system inefficiency, the specification of the cost function becomes

$$\ln c = K + \frac{1}{r} \ln Y + \sum_{i=1}^{n} \frac{\alpha_i}{r} \ln pi - \frac{1}{r} (v-u) + (E-\ln r)$$

where $E = \sum_{j=2}^{n} \frac{\alpha_j}{r} \varepsilon_j + \ln [\alpha_1 + \sum_{j=2}^{n} \alpha_j e^{-\varepsilon_j}]$

and $\varepsilon = v-u$.

The expression E attains a minimum value(ln r) when $\varepsilon_2 = \varepsilon_3 = \ldots = \varepsilon_n = 0$. The non-negative value of ($E-\ln r$) is the addition to ln c, attributable to system inefficiency.

These detailed descriptions of the specification and estimation of the cost functions suggest to us that the approach is feasible. In particular,

(i) Certain aspects of the multi-output and dynamic cost structure of steam electric power generation can be introduced into the specification.

(ii) Though there are practical difficulties, it is possible to distinguish between the ex ante and ex post specification of the cost functions.

(iii) Even certain stochastic variations in production, their effect on input choices, and consequent changes in the cost curves can be introduced.

(iv) However, not being based on any rigorous specification of multi-output production functions, the specifications are somewhat ad hoc.

(v) Despite the flexibility they afford, the specifications have not yet been adequately dynamic to answer the questions posed at the outset.

(vi) Similarly, the specification of the stochastic cost frontiers does not appropriately indicate the *ex ante* and *ex post* fuel substitution possibilities.

3.5 A FEW FURTHER OBSERVATIONS

The foregoing review of literature indicates that the production function approach, though it indicates the presence of structurally different constraints on the input choices, *ex ante* and *ex post*, could not estimate them from the available data[12]. A similar problem appears to hold even

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12. The programming approaches, e.g., Anderson (1972), Turvey (1968), Baughman (1974), Scherer (1976), Noonan and Giglio (1977), Rowse (1978) and Cote and Laughton (1982), which emphasize these constraints, have also been insufficiently specific. They tend to specify the constraints *ex ante* and do not allow any testing of their validity in a concrete empirical context. Secondly, it is possible that the *ex post* data, which generally constitutes the basis of analysis, already embodies these constraint qualifications. Stated differently, if the estimated models are used with caution and recognized as applicable only in a limited region, the necessity to estimate constraints explicitly can be minimized.

in the context of input demand estimation. However, even if this problem can be minimized or accounted for in the specification it appears doubtful if these two methods would be really efficacious for the purposes of our present study. The inherent deficiencies of these approaches, detailed in Sections 3.2 and 3.3 appear to be insurmountable.

The cost function approach offers greater flexibility despite some of its _ad hoc_ nature. For, the above review of the existing studies indicates that it can, with suitable modification of the specification, accommodate the different aspects of the decision making intricacies of steam electric power generation. However, it has been recognized that the

(i) hierarchical structure of decision making,

(ii) distinction between _ex ante_ and _ex post_ input choices, and

(iii) extent of input flexibility when confronted with a stochastic production process,

are not adequately modelled. Since these aspects are central to the analysis of the present study, an attempt will have to be made to recast the essential details in an operationally more pertinent framework.

CHAPTER 4

SPECIFICATION OF THE COST FUNCTIONS

4.1 MODELLING DYNAMIC COST FUNCTIONS

Production costing and reliability models of electric power systems[1] are used to estimate the cost of operating the electrical generators. The effect of demand patterns, fuel costs, generator characteristics, and reliability on system cost can be studied by the use of such models.

In order to approach the problem of specifying the cost function satisfactorily we briefly recall the following aspects :

(i) In general, it may be considered necessary to operate the power systems so as to cater to the fluctuating load on the power plants from instantaneous generation and at the lowest possible cost. But, it was noted that it is not technologically feasible to connect a power plant directly to load. Instead, attempts are made to monitor the power

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1. The reliability of a power system is defined with reference to two indices of risk, viz., (i) the expected value of the energy not supplied over a certain period of time on the assumption that the adjustment of load to availability is carried out, and (ii) the expected value of the power disconnected without forewarning during the period of time as a consequence of the unavailability of the elements of the system.

flow throughout a Regional grid so as to operate each of the generators at a steady rate of capacity. Hence, the fluctuations over short time intervals are generally eliminated[2]. But there may be changes planned for average utilization over different months.

(ii) From an organizational viewpoint, it was noted that there is a two-level decision structure. The first level deals with ex ante choice of the size of plant and determines the average capacity utilization rate given the expected load on the system. The actual operational details and ex post planning of the operation of a power plant which is already installed are determined by a different group of decision makers.

(iii) Even in the best managed plants there would be some forced outages. Consequently, the production system is inherently stochastic. Faced with these uncertainties the managers of power plants readjust their operational decisions. In particular, there will be changes in the fuel-mix utilized to deliver a given amount of energy. There may be some changes warranted even in the ex ante plant size and design decisions.

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2. Transmission costs are an important dimension of system costs. But most production costing models, including the present study, do not consider transmission or stability constraints.

(iv) There are multidimensional aspects of both output and capital in power plant operations. These dimensions have differential impacts on costs. Further, by the nature of the multi-output definition, the cost structures have an inherent dynamic character.

The primary purpose of this Chapter is to make an attempt to incorporate these aspects in a dynamic specification of cost functions. The basic framework adopted consists of a standard production costing methodology which incorporates the choices regarding the average generator output, plant size, and fuel-mix. The model would first be presented in a deterministic set up in which we abstract away from the uncertainties regarding power supply. The model would subsequently be expanded to account for the stochastic nature of production in which the variability of power supply due to plant failures is explicitly considered. When this is accomplished we would endeavour to show how it can be utilized to study the inherent dynamic inefficiencies.

4.2 COMPONENTS OF DYNAMIC COST

The operations of a power plant are usually directed to deliver energy denoted by

$$Y = (720 \text{ or } 744)\ (b)\ (IC)$$

where Y is monthly kWh demand, 720 or 744 is hours per month, b is percentage of monthly hours of operation of the plant, and IC is installed capacity.

Following the standard conventions of economic analysis it would be convenient to view the total costs of output generated by a power plant as comprising of two dimensions

$$TC = CC + PC$$

where TC is total costs, CC is capital cost , and PC is production cost .

The capital cost component can, in turn, be examined in several steps. The initial expenditure of funds for investments in capital equipment can be expressed as some function of the installed capacity. This, in its turn, results in annual investment charges which are usually expressed in terms of a percentage of capital cost. These fixed charges consist of (i) depreciation, (ii) rate of return on initial capital, and (iii) taxes and insurance.

In general, given the technology, it was observed that the capital costs do not increase proportionately with the size of the installed capacity. Existence of economies of scale upto a capacity limit of 300 MW has been demonstrated. As such there are aspects of efficiency in the choice of

size which reduce the capital cost per kwh of energy as the installed capacity increases.

However, the technology does not remain invariant as the installed capacity increases. The latter embodies some essential changes in the designs. In general, choices of throttle pressure, and airpreheaters and economizers would be needed to improve the efficiency of the steam cycle. Consequently, the initial capital cost of the power generating equipment increases with efficiency. This, in turn, results in an increase in annual capital costs since the fixed charge rate depends upon the embodied technology.

From this analysis, it appears that the capital cost per kWh of energy generated depends non-linearly on the installed capacity[3].

The capital cost attributable to a unit of energy generated by a plant also depends upon the degree of capacity utilization. For, given the installed capacity of the plant there are certain unavoidable annual fixed costs. At low capacity utilization, the fixed charges are shared by a smaller number of units of energy and result in relatively

3. This would be a more meaningful approach. Making attempts to separate the technical efficiency aspects of embodied technology have no relevance in the present context.

high unit energy cost . In contrast, at high rates of capacity utilization, the same fixed charges are shared by a larger number of units of energy to reduce the capital cost per kWh. At the same time, the wear and tear of machines, or the depreciation of plant and machinery, generally, increases with capacity utilization so as to add an increasing component to capital costs per kWh. It may, therefore, be expected that the CC/kWh will exhibit essential non-linearities both with respect to the installed capacity and the capacity utilization rate.

The production costs associated with the plant can be written as

$$PC = FC + OM$$

where FC is fuel cost, and OM is costs of operations and maintenance. Let us consider the nature of these cost components in turn.

The largest item of expenditure in the operation of a thermal power plant is the original raw energy in the form of fuel. Coal, oil, lignite and natural gas usually constitute the major fuels. The fuel cost varies with the amount of energy produced and the efficiency of the plant.

Referring back to Chapter 1, Section 4, we recall that for a given boiler turbine generator (BTG) set, the designed heat rate varies with the rate of capacity

utilization. For, it is expected that the boiler efficiency varies non-linearly with the load which the system has to deliver. Consequently, the fuel costs vary non-linearly with fuel-mix and target rate of capacity utilization.

Consider the OM costs next. Every well-managed plant follows a plan of preventive maintenance. Inspection, cleaning, and overhauling apparatus are taken up on a regular schedule to forestall the possibility of breakdowns during service. This item of expenditure is made up of two components : materials used for repairs and maintenance labour. The maintenance and repair costs increase with generation, most of the increase being caused by the steam generator deterioration with service.

Labour is required in a steam electric generating plant for unloading and storing fuel and disposing off the refuse. Boiler operation requires labour. Usually a different group of workers will be assigned to (i) the combustion phase, and (ii) the water being supplied to the boilers. Manual attention is often necessary to start, monitor, and stop the operations of the prime movers during the generation phase. This is necessary even in some hydraulic and gas turbine plants which are automatic in operation. Similarly, loading of generators is usually assigned to a specific group of workers.

Quite clearly, there are fixed cost components as well as variable costs in these wage cost specifications. There is no *a priori* reason why these costs vary linearly with power plant utilization.

Supplies usually cover such items as water for make-up and general use, lubricating oils, water treatment chemicals, tools, and so on. In general, any items that are not included in the categories of fuel or maintenance are charged to the supplies account. Supervision and supplies will often remain substantially constant for all rates of operation though some plants may show a slight increase with increasing generation.

In some accounting classifications of the maintenance costs, several of these items are treated as fixed costs and are included in the capital cost account. Such choices appear to be a matter of arbitrary managerial policy.

4.3 IMPLICATIONS OF THE HIERARCHICAL DECISION PROCESS

Referring to Chapter 1, Section 3, observe that there is a two-stage decision making process in the design and operation of the power plants. In the present section we will endeavour to identify the appropriate form of specification of the cost curves in such a decision making milieu.

Recall that at the system level, the Central Electricity Agency and the Planning Commission are entrusted with the responsibility of planning with respect to the power generating capacity at appropriate geographical locations. Given a load duration curve over a Regional grid and the availability of the minimum inputs to set up a plant, these agencies determine the capacity which must be installed. That is, the choice of installed capacity is determined by the optimal flow rate of capacity utilization given the load pattern on the system and the generally accepted technical norms for power plant maintenance. It appears from this analysis that the installed capacity and the rate of capacity utilization are the primary decision variables at this level.

The pertinent question would then be the following : What are the cost considerations which they take into account in this decision making process? It appears to us that the prevalent practice of engineering and managerial economics would be the best guideline . Since capital costs are by far one of the largest components in the total costs, the tradition has been to define the optimal size and utilization of capital installations on the basis

of these costs alone[4].

At the planning level, different plant sizes are chosen so that the various plants connected to a grid can cater to the peak load on the system. For example, a 150 MW unit was added in 1965 to Trombay (Tata) power plant's existing capacity to meet 20 percent of the system peak load[5]. A larger installed capacity will mean a lower capital cost per kWh of energy delivered whatever

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4. Economic theory, on the otherhand, generally postulates that the choices of capital stock and fuel-mix are simultaneous given the level of output to be produced. In the present context, due to the technological constraints on power generation and the fact that the plants are not connected to the load this approach is inoperative. The strength of the empirical observation in the power generation activity appears to justify the approach suggested here in preference to the conventional economic theory. However, it may be noted that neglecting the operating cost may result in slightly higher choices of installed capacity and the utilization rate.

5. c.f. Thakor, Malhotra and Narayanan (1972), p. 93. However, note that there is a difference in the concepts. In their study the system peak load is defined as the maximum simultaneous ultimate customer demand which occurs during the period as measured by actual deliveries at bulk power sources. The peak load in the above study also includes line losses but no auxiliary power requirements. Where the systems are not at present inter-connected, the peak load shown is the aggregate of the peak loads of the individual systems. Where systems are fully inter-connected and fully co-ordinated, the peak loads refer to the sum total of the diversified loads.

be the level of utilization. However, since the peak load occurs only for a short duration of time, a larger plant would remain idle by a greater proportion and for longer intervals of time. A lower rate of utilization even in the presence of a lower initial capital cost may still result in a higher capital cost per kwh of generation. Alternatively, if a smaller size plant is chosen there may be a higher capital cost per KWh of energy delivered and, in addition, there would be a greater probability that the plant cannot cater to the peak demand experienced on the system. The designer has to balance the increased capital cost component against the possible cost of supply shortage in order to arrive at the economically viable unit size. It is against this backdrop that a specific optimal rate of capacity utilization can be defined for each choice of installed capacity and conversely by considering the capital cost components alone. The capital cost considerations may be so dominating that the choice of the optimal rate of capacity utilization may be purely on these considerations even when there are some operating cost specifications which these changes entail.

The analysis of the previous section also indicates in a fundamental manner that the capital cost of a KWh of energy depends non-linearly on the installed capacity and capacity utilization. On the basis of these findings it

was decided that the capital cost equation would be developed independently.

When the power plant is entrusted to the State Electricity Boards (SEB's) for actual operation, they no longer consider capital cost as an essential element in their decision making process[6]. Instead, they view (i) the stock decisions with respect to planned outages and maintenance, i.e., planned utilization rate, and (ii) the flow decisions regarding fuel-mix and heat rate, as their primary concern.

It has generally been noted that power supply falls short of the demand on a grid. Consequently, most of the plants have been operating at or close to capacity limits. However, the plant availability depends upon the proportion of time that the plant is shut down for planned maintenance, and for unforeseen breakdowns, i.e., forced outages. The planned utilization rate, defined by (1-planned outage rate), constitutes a decision choice of the operational management. The working norm will have to be defined on the basis of technical as well as operating cost considerations. It, therefore, appears plausible that decisions regarding

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6. In the deterministic case they would view this as a sunk cost. Further, they may feel that they can not alter or influence these decisions on the basis of operating cost considerations.

PUR, HR, and fuel-mix are developed with the costs of fuels and operations and maintenance in view.

4.4 THE DETERMINISTIC MODEL

The modelling of the cost curves may now be detailed with the above information as the background. We will consider the deterministic formulations in the present section.

In consonance with our hypothesis of Section 4.2, it will be presumed that at the system level, the planners decide a stock variable, viz., installed capacity (IC) and a flow variable, capacity utilization rate (CU), based on capital cost considerations. The analysis upto this point only indicated that the capital cost per kWh may exhibit essential non-linearities with respect to both IC and CU. However, it is not as yet possible to conceptualize any production function which incorporates these stock and flow inputs so that a cost function can be developed from it. Similarly, as in the case of the long-run cost functions of standard theory[7], there is no unambiguous functional specification which can convey the essential U-shape of these average cost relationships with respect to both IC and CU.

7. See Walters (1963) and Gold (1966) who examined this issue more concretely though in an altogether different context.

Hence, starting from the basic specification

$$CC = f(IC,CU)$$

the following functional forms were utilized in an attempt to isolate the nature of the non-linearity[8].

$$CC = a_o+a_1(CU)+a_2(1/CU)+a_3(IC)+a_4(1/IC)+a_5(IC(CU)$$

$$CC = a_o-a_1(CU)+a_2(CU)^2-a_3(IC)+a_4(IC)^2+a_5(IC)(CU)$$

$$CC = a_o-a_1(CU)+a_2(CU)^2+a_3(IC)+a_4(1/IC)+a_5(IC)(CU)$$

$$CC = a_o+a_1(CU)+a_2(1/CU)-a_3(IC)+a_4(IC)^2+a_5(IC)(CU).$$

However, this _ex ante_ specification of the unit capital costs is subject to a fundamental limitation. It is applicable only if IC is a continuously varying decision variable. This assumption is not satisfied in time series analysis especially over relatively short periods of time.

It was therefore, expected that the CU variable alone would be significant in the time series analysis. On the other hand, a cross-section data for several firms, taken over a fixed length of time, for instance, one quarter , would depend on both IC and CU as specified by this formulation. The empirical relevance of this distinction would become evident in Section 4.6 where we will examine the methods of determining the sources and extent of inefficiency.

8. To an extent the choice was governed by the empirical experiences reported by Stewart (1979) and some initial experimentation.

Quite trivially, the first partial derivatives of these cost equations, with respect to IC and CU, when set equal to zero, provide the necessary conditions for cost minimization. It may be noted that the second-order conditions are also satisfied. Using the second alternative functional form of the cost specification they can be exhibited as

$$\frac{\partial CC}{\partial IC} = -a_3+2a_4\ IC+a_5\ CU = 0$$

$$\frac{\partial CC}{\partial CU} = -a_1+2a_2\ CU + a_5\ IC = 0$$

The optimal IC and CU can be solved from these two equations to obtain

$$IC = \left(\frac{a_1-2a_2}{a_5}\right)\left(\frac{a_3a_5-2a_1a_4}{a_5^2-4a_2a_4}\right), \quad \text{and}$$

$$CU = \left(\frac{a_3a_5 - 2a_1a_4}{a_5^2 - 4a_2a_4}\right).$$

Under the assumptions of the deterministic case there is no production uncertainty as such. Consequently, whatever, output is planned for can be delivered and the difference between the plant availability and the rate of

capacity utilization ceases to exist. The only meaningful choice available to the operational managers is with respect to the fuel-mix.

The actual choice of fuels depends both on the *ex ante* alternatives available as well as the relative prices. But our purpose is to exhibit the available alternatives along an iso-cost curve. Technological possibilities regarding fuel substitution[9] can be more usefully exhibited if we hold the fuel prices constant throughout the analysis. However, as remarked earlier, these choices are constrained. Hence, from the viewpoint of practical details, the functional specification which we adopt would be applicable only for the relevant range[10].

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9. In standard specifications of the cost curves the variable costs have been postulated to depend on relative prices alone. The actual levels of inputs are not included in the specification. They are developed from the Shephard's (1953, 1970) duality theorem. But, in the present context, we do not have such a procedure due to the inadequate economic theory. It was, therefore, necessary to approach the estimation problem directly. The data will be adjusted in such a way as to confirm to these specification requirements.

10. In other words, empirical validation of these specifications requires that the optimal fuel-mix combinations should not be too far off the observed magnitudes. We may alternatively look upon such an exercise as a first-order approximation towards efficient use of inputs. Utilizing such an approach interactively may ultimately reveal the complete range of *ex ante* possibilities.

With these notions and limitations in perspective, the fuel cost equation may be written as

$$FC = g(HR, X_i/Z)$$

where FC is fuel cost per KWh, HR is heat rate (Kcal/KWh), X_i is the ith fuel (Kcal/kWh) used in the production process, and Z is the major fuel (Kcal/kWh) used for firing the boiler.

As before, we experimented with the following alternative specifications so that an appropriate form of the non-linearity in the cost functions can be identified on an empirical basis.

$$FC = b_o+b_1(HR)+b_2(1/HR)-b_3(HR)(CU)+ b_4(X_i/Z)+b_5(1/(X_i/Z))$$

$$FC = b_o+b_1(HR)+b_2(1/HR)+b_3(HR)(CU)-b_4(X_i/Z)+b_5(X_i/Z)^2$$

$$FC = b_o-b_1(HR)+b_2(HR)^2-b_3(HR)(CU)+b_4(X_i/Z)+b_5(1/(X_i/Z))$$

$$FC = b_o-b_1(HR)+b_2(HR)^2-b_3(HR)(CU)-b_4(X_i/Z)+b_5(X_i/Z)^2$$

Simple cost minimization techniques will again yield efficient (i.e., satisfying both first-order and second-order conditions) choices of HR, X_i and Z for a given value of CU[11].

11. It is quite clear that for a specified CU there is a choice of HR irrespective of which fuel combination is used to deliver it. By this argument, given HR the choice of CU does not have any further effect on the choice of the optimum fuel-mix.

From the foregoing presentation, it is obvious that there would be a basic difference in the specification of the models if they have to be made realistic by incorporating the stochastic nature of the production process. We will consider this in some detail in the following section.

4.5 THE STOCHASTIC MODEL

The energy potential available at a thermal power plant will theoretically be equal to (720 or 744 x installed capacity) in KW per month. But, as the boilers are to be overhauled as per statute every twelve months and in view of various other types of breakdowns that may occur in a high pressure steam cycle system, the actual generation achieved will be far less. The overall economy of a thermal plant improves and the cost of generating a unit of energy gets progressively reduced with the increase in energy generated at the plant. It is, therefore, expected that the management and staffsof a power plant makes all efforts to maximize generation.

The outages of generating units at a plant can be classified into the following categories :

(i) planned outages for overhaul and preventive maintenance,

(ii) forced outages resulting in complete shutdown over a relatively small interval, and

(iii) partial loss where the unit is in service but is not generating the desired output due to defects in parts of the system like failure of a mill, or I.D. fan, and so on.

By definition, the energy cost associated with power production is the cost of providing a unit of output, i.e., a KWh. Since the demand for power is periodic, varying with the time of the day and the season of the year, and its supply basically non-storable, the cost of supplying the requisite energy also varies. Consumption of power during peak hours requires running high cost units more intensively, while off-peak consumption can be met by operating lower cost units at a much cheaper fuel cost. So, the cost of providing electricity is actually time-dependent[12], it being higher during periods of peak demand relative to the off-peak demand period

In the present section an attempt will be made to model the dynamic cost components taking into account the uncertainty regarding both the demand for power and the availability of generating units. Such a specification will provide a computationally efficient procedure to obtain the optimal IC, CU, PUR, HR and fuel-mix under

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12. See Kirchmayer et al. (1955), Sagar and Wood (1973), and Zahavi et al. (1980) for details.

conditions of uncertain demand for and supply of power.

Reconsider the specification of the capital cost (CC/kWh) equation. In the present context it can be written as

$$CC = m(CU, IC, PUR, PLF, FOR)$$

where PUR, PLF and FOR are exogenous variables. As noted in Section 4.3 a growth of the load on the system gives rise to a choice of IC along with CU purely on capital cost considerations. In the presence of uncertainties, e.g., in PLF and FOR, a new configuration of IC and CU will be chosen. Similarly, for a given PUR the optimal CU will depend on exogenously determined outages.

The following alternative functional forms have been estimated so that the appropriate specification of non-linearities can be identified.

$$CC = d_o - d_1(CU) + d_2(CU)^2 - d_3(IC) + d_4(IC)^2 + d_5(IC)(FOR) + d_6(IC)(CU) - d_7(CU)(PUR).$$

$$CC = d_o + d_1(CU) + d_2(1/CU) + d_3(IC) + d_4(1/IC) + d_5(IC)(FOR) + d_6(IC)(CU) - d_7(CU)(PUR).$$

$$CC = d_o + d_1(CU) + d_2(1/CU) - d_3(IC) + d_4(IC)^2 + d_5(IC)(FOR) + d_6(IC)(CU) - d_7(CU)(PUR).$$

$$CC = d_o - d_1(CU) + d_2(CU)^2 + d_3(IC) + d_4(1/IC) + d_5(IC)(FOR) + d_6(IC)(CU) - d_7(CU)(PUR).$$

Once again setting the first partial derivatives with respect to CU and IC to be zero, we determine the optimum values of CU and IC for exogenously specified values of PLF, PUR and FOR. It may be noted that the second-order conditions for cost minimization are also satisfied.

It was noted in an earlier section that the repair costs and OM (operation and maintenance) costs can be treated as being similar to the capital cost component. This is especially relevant if we recognize the fact that they are more closely related to the rate of capacity utilization rather than fuel-mix and fuel usage. However, in the stochastic case they cannot be considered to be primarily a function of the CU. Instead, the forced outages may necessitate unexpected additional costs of repair as well as operations and maintenance. Consequently, these components should be added to FC (fuel cost/kWh) to define VC (variable cost/kWh) rather than add them to CC (capital cost/kWh). This would be the more appropriate procedure even from an accounting viewpoint.

In any given problem set up, drawing up plans can only be on a long-term basis and often by utilizing incomplete information. Thus, for example, the plans for IC may span a number of years. Similarly, a plan for plant availability and PUR, even if it can apply for as short an interval of time as a month, may nonetheless be incapable of visualizing

the weekly and daily requirements. Fuel choices, on the other hand, may turn out to be a daily or even hourly choice. Consequently, it can be argued that PUR may be determined on the basis of broad general information regarding FOR and PLF to minimize the sum total of all the operating costs. On the contrary, fuel-mix variations may be necessitated at shorter time intervals over which the commitments for repairing, and other maintenance expenditures cannot be altered. It may even be argued that such changes are not warranted. Thus, there are various degrees of fixity and variability in the power plant operations based on the nature of the environmental changes, types of decision choices, and the associated cost implications.

For the present purposes, it appears that CC, VC, and FC being treated separately and being considered as the result of different decisions is warranted.

Even from an econometric viewpoint such a classification of the cost components is essential. For, suppose the fuel costs are not the dominant component of the variable costs. Then, if we include the fuel-mix variables in the VC equation they would be insignificant. On the contrary, if they are a significant proportion then the optimal choice of PUR cannot be properly identified. Hence, the appropriate dimension of cost components over an appropriate time horizon and suitable specification of decision choices appear to be a useful approach in the analysis of the cost functions.

It, therefore, appears pertinent to define even the choices of operational management in two stages. Firstly, it may be conceptualized that a planned utilization rate (PUR) is chosen for a given PLF and FOR on the basis of VC (i.e., the sum of fuel cost, repair cost, and operation and maintenance cost) per kWh. That is, we may write

$$VC = h(PUR, PLF, FOR)$$

The following functional forms have been estimated and a suitable choice is made on the basis of empirical performance.

$$VC = C_o - C_1(PUR) + C_2(PUR)^2 - C_3(PUR)(PLF) + C_4(PUR)(FOR)$$

$$VC = C_o + C_1(PUR) + C_2(1/PUR) - C_3(PUR)(PLF) + C_4(PUR)(FOR)$$

$$VC = C_o - C_1(PUR) + C_2(PUR)^2 - C_3(PUR)(PLF) - C_4(PUR)(FOR)$$

$$VC = C_o + C_1(PUR) + C_2(1/PUR) - C_3(PUR)(PLF) - C_4(PUR)(FOR)$$

By standard optimization methods, an efficient (i.e., both first-order and second-order conditions of cost minimization are satisfied) PUR will be determined for exogenously specified values of PLF and FOR.

However, the FC equation of the deterministic model carries over to even the stochastic case without any changes. For each level of CU, computed from the CC equation in the

stochastic model, we have an unique HR and consequently fuel-mix, which can be obtained from the FC equation.

4.6 MEASURES OF INEFFICIENCY

The performance of a steam electric power plant is considered to be efficient if a KWh of energy is delivered at the bus-bar at the lowest possible cost. This is generally accomplished by an appropriate choice of installed capacity, plant availability, and fuel-mix. Inefficiency in the operation of a power plant may be a result of inappropriate choice of one or more of these dimensions. The actual operations of the power plants do indicate the existence of inefficiency since there is substantial difference between the actual choices to inputs and their efficient levels. Hence, the analysis of the present Section would make an attempt to separate the sources and extent of inefficiency by adopting the cost function methodology which we have chosen.

Consider the notion of system inefficiency first. If the load on the system, within a given Regional grid, is well within the range of economies of scale in power generation, then the time rate of demand would essentially determine the optimum IC. However, this is unlikely given the relatively large demand on the Regional grids. In such a case the optimal IC and the number of power plants which cater to the given demand would be determined by considerations of the

technically efficient choice of IC alone. That is, the optimal IC would be one which minimizes the cc/kWh assuming that the IC chosen would be planned for an efficient rate of utilization[13]. When the optimal IC so obtained is compared to the actual IC, we get a measure of system inefficiency.

Since the production system is subject to stochastic variations in FOR and PLF, both the efficient CU and the corresponding efficient IC would be altered. Consequently, an efficient IC was computed for an optimal choice of CU. The system inefficiency measurement remains the same with this modification.

Referring to Section 4.2, it may be recalled that for a given IC, the cc/kWh depends on the choice of CU. Hence, conceptually, a plan for CU may be considered to be efficient if cc/kWh is minimized. Planning inefficiency may then be defined as the deviation of the actual CU from that which minimizes cc/kWh at the efficient level of IC.

From this description of the efficient choices of IC and CU it is obvious that they are interrelated. Consequently, the efficient levels of IC and CU may be determined simultaneously by minimizing cc/kWh. In practice, we adopted such a procedure. An adjustment, analogous to that in the case of

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13. The actual computation of this would be clear from the analysis which follows.

system inefficiency, has been introduced in the stochastic case.

However, in the context of the time series analysis over a relatively short time interval, IC does not vary much. Hence, the primary variation in cc/KWh is accounted by the levels of CU. It follows that only planning inefficiency can be conceptualized and estimated in such a context.

At the operational level, the decision makers do not have any choice of the unit/plant size. Instead, their efforts are usually directed to the provision of the requisite energy demanded at the lowest possible operating cost. In the deterministic case, this would consist of choosing an appropriate fuel-mix to minimize the fuel cost per kWh. Hence, the efficient fuel choices can be defined for an efficient level of CU. The deviations of actual HR and fuel-mix from the efficient levels then give us an estimate of the operational inefficiency. However, notice that there is an aspect of planning inefficiency carried over to the operational level. For, even in the absence of operational inefficiency, an inappropriate choice of CU may result in a sub-optimal choice of HR and the fuel-mix. This can be identified by substituting actual CU for the efficient CU and reestimating the efficient HR and fuel choice.

This procedure completely specifies the method by which system inefficiency, the two dimensions of planning inefficiency, and operational inefficiency can be separated.

The stochastic case poses a slightly different problem. For, in this case the PUR differs from CU to the extent that a higher rate of availability may have to be planned. Certain repair and OM costs are inevitably incurred once the PUR is decided. An element of inefficiency is introduced at this level in addition to the possibility of a sub-optimal choice of fuel-mix. But no new procedural difficulties are encountered.

Figures 4.1 and 4.2 have been drawn up to synthetically represent the overall model structure and the proposed measures of inefficiency. Figure 4.1 highlights

(i) the stock and flow concepts of decision variables,

(ii) the *ex ante* and *ex post* dimensions of problem at hand,

(iii) the classification of cost components in deterministic as well as stochastic models, and

(iv) the interrelationships between the deterministic and the stochastic models through the common fuel cost equation which determines optimal choice of HR and (X_i/Z).

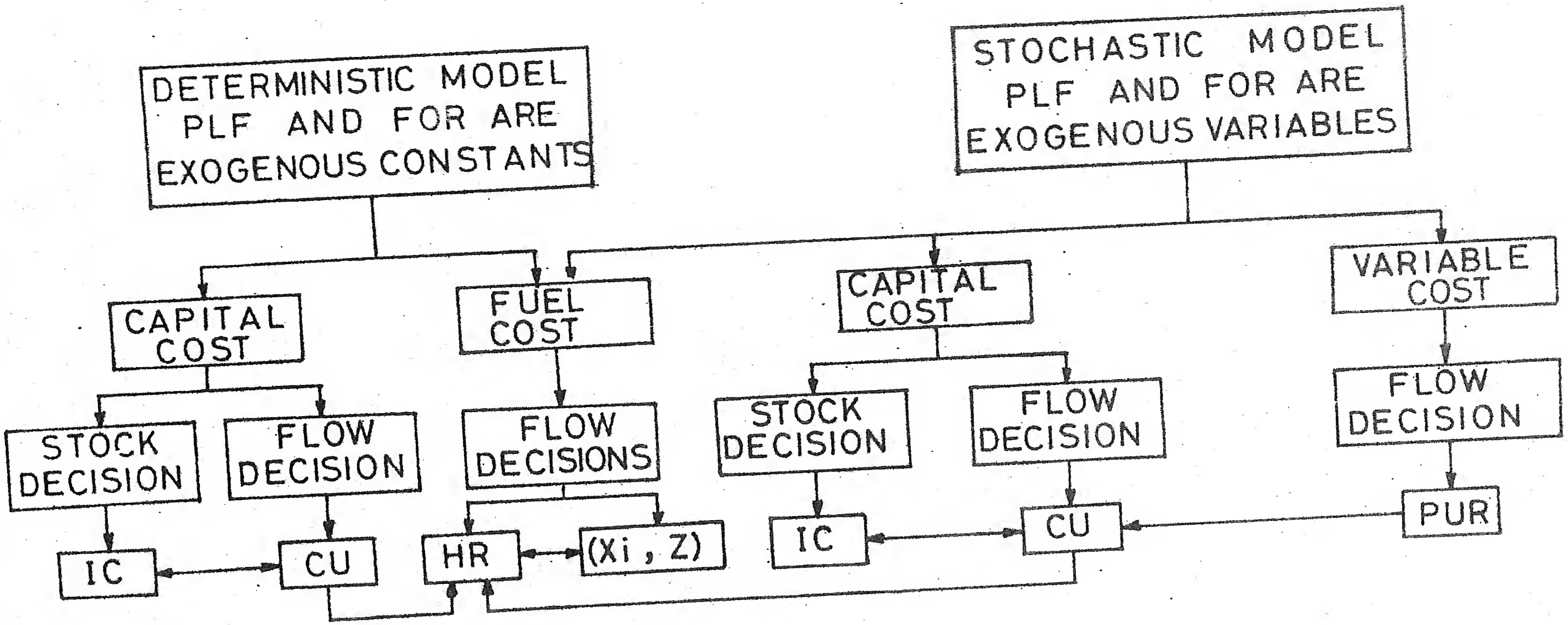

FIG. 4.1 OVERALL MODEL STRUCTURE

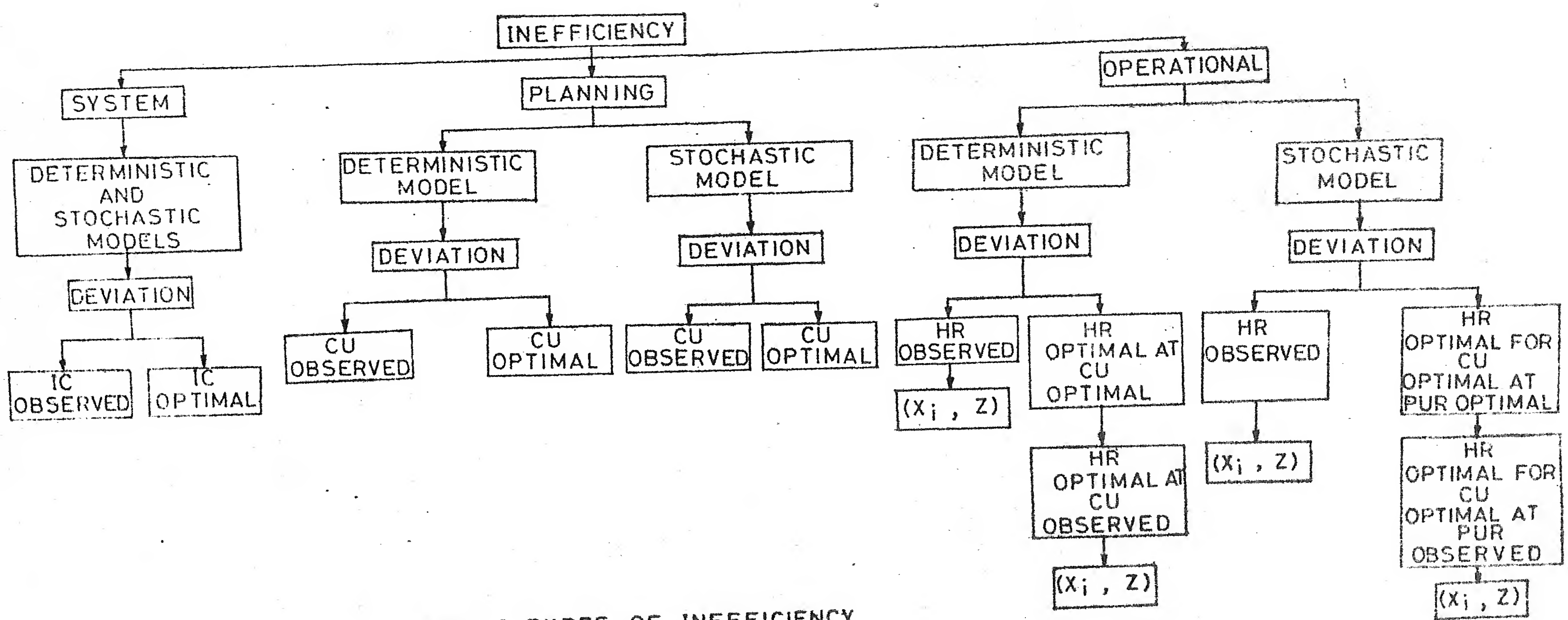

FIG. 4·2 TYPES OF INEFFICIENCY

Figure 4.2 delineates the salient features of the concepts of inefficiencies and their compatibility with the general methodology proposed in this study.

CHAPTER 5

DATA AND MEASUREMENT OF VARIABLES

5.1 NATURE OF DATA

The load duration curves of most of the steam electric power plants vary over the different hours of the day, different days of the week and so on. Hence, it may appear that such a disaggregate level data would be necessary to provide any comprehensive analysis. However, it should be recognized that it is never technologically feasible to connect any power plant to load directly. The basic reason for this is, of course, the change in the frequency[1] and tripping that is expected beyond a small range of variation of the power plant. Instead load dispatching is left to an agency other than the individual power plant. Consequently, the daily and may be even the weekly fluctuations are ironed out by appropriate loading defined for each plant. Even from a practical viewpoint any more detail than monthly data would not be available, especially for the capital cost components, due to their accounting nature.

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1. Frequency is the rotation of the L.P. blades in turbines measured as the number of cycles per second.

The requisite data, even at this level of aggregation, was not available from any published sources. Various government agencies had to be approached personally and the information obtained from their records[2]. As such, there was a limitation on the size of the sample covered by the study. We can only claim that the power plants under study constitute a broadly representative spectrum of the different experiences we expected a priori.

Twenty six thermal power plants, located in different Regions of the economy, constitute the ultimate sample for which all the required data could be assembled on a comparable basis. Appendix 5.A provides a detailed account of power plants under study. Monthly information was obtained with respect to :

(i) Capital cost

(ii) Fuel cost

(iii) Operation and maintenance cost

(iv) Repair cost

(v) Plant load factor

(vi) Capacity utilization rate

(vii) Heat rate

(viii) Fuel consumption

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2. The data was made available to us on the understanding that it will not be published or made available to others. Hence, we will describe the details as far as practical.

(ix) Planned outage rate

(x) Forced outage rate, and

(xi) Planned utilization rate

In Appendix 5.B, we reproduced the prescribed CMQ 10 format, released by the Commercial Directorate of the Ministry of Energy for compiling month-wise and plant wise information. The necessary information was made available on these formats by the following organizations :

(i) Commercial Directorate
Central Electricity Authority
Safdarjang Enclave
New Delhi.

(ii) Planning Division
Central Electricity Authority
Sewa Bhavan
R.K. Puram, Sector 1
New Delhi.

(iii) Grid Operation
Central Electricity Authority
Safdarjang Commercial Centre
New Delhi.

(iv) Thermal Directorate
Power Systems, OMT
Central Electricity Authority
R.K. Puram
West Block, Sector 1
New Delhi.

(v) State Electricity Board Offices.

(vi) Chief Engineers' Offices
Thermal Power Plants.

5.2 COMPONENTS OF CAPITAL COST

Capital cost of thermal power plants consists of

(i) Preliminary : Levelling and surveying;

(ii) Land, Drainage and sewage : Land for power plant (house) including compensation given; Development charges; Drainage, Sewage and water supply in power house and colony;

(iii) Works: Main building including steel structure for power plant buildings, bricks and floor works; pumphouse and pipe laying for water treatment; canal works; pump-house and plant foundation including tiles; underground coal bunkers; switchgear room for inter-connection; railway sidings and roads inside the power plant.

(iv) Buildings: Residential buildings; colony; inspection bungalows; roads inside the colony;

(v) Special tools and equipments: Generator; Turbo-generator; Boiler;

(vi) Interest charges;

(vii) Depreciation;

(viii) Audits and accounts, Establishment charges, Management expenses; and

(ix) Salaries and wages.

A detailed account of the capital cost calculation has been reported in Part II of the CMQ 10 schedule reproduced in Appendix 5.B. It is well-known that in most of the manufacturing establishments as well as the power plants there has been a tendency to maintain a fixed number of employees of the operation, maintenance and managerial categories. The wages and salaries of these workers may therefore be included as components of fixed cost. The wages and salaries paid to casual and contractual labour were not available in the data obtained from the above source. Generally, on an average, the establishment charges required during construction and the management expenses are 12 percent and 8 percent of total capital cost respectively. Similarly, the interest charges are of the order of 7 to 9 percent per annum. The depreciation charges, however, vary from one month to another depending upon the schedule of power generation. To that extent this is not a fixed cost in the conventional economic sense. It depends on both the dimensions of capital and output alluded to earlier.

5.3 COMPONENTS OF OPERATION AND MAINTENANCE COSTS

The Operation and Maintenance (OM) costs, apportioned on the basis of gross energy generation, comprise of

i) Cost of water, chemicals,

(ii) Lubrication and other consumable stores:
Servo super, servo ultra, Terbinol, Gear oil, Hydraulic brake fluid, Servo engine oil, Transformer oil, M.P. grease etc.,

(iii) Accessory electric plant equipment: spare parts, and

(iv) Plant supplies and miscellaneous expenses.

5.4 COMPONENTS OF REPAIR COST

Repair cost, other than planned maintenance, will have to be incurred whenever the boiler and turbo-generator are inoperative due to unexpected outages. These outages can be classified into the following components :

(i) Planned outages for overhaul and preventive maintenance,

(ii) Partial outages, e.g., the unit being in service, but not giving full output due to defects in the part of the system like failure of a mill or I.D. fan etc.

Technically, outages are originated in the following areas :

(i) Turbine including lubrication system and steam valves,

(ii) Boiler pressure parts, boiler feed system,

(iii) Coal mills and milling system,

(iv) Air and gas system,

(v) Power transformers, instrumentation,

(vi) Switchyard equipment, and

(vii) Grid disturbance etc.

The costs incurred on each of the occasions when an outage occurs are recorded separately though they cannot be explicitly categorised according to each of the sources mentioned here.

5.5 COMPONENTS OF FUEL COST

For coal-burning boilers, cost of coal is calculated at bunkers and added up.

(i) Cost of coal ex-colliery,

(ii) Royalty,

(iii) Excise duty,

(iv) Coal cess,

(v) Sales tax,

(vi) Railway freight,

(vii) Clearance charges,

(viii) Siding charges,

(ix) Maintenance cost of coal,

(x) Shunting charges,

(xi) Feeding charges, and

(xii) Octroi.

For gas-turbine plants, cost of natural gas has been calculated along the same lines as the cost of coal.

For oil-fired boilers, the cost of oil (e.g., light diesel oil, furnace oil, residual fuel oil, etc.) is

calculated in the following manner :

(i) Cost of oil ex-refinery,

(ii) Railway freight,

(iii) Sales tax and other miscellaneous taxes,

(iv) Clearance charges,

(v) Railway siding charges,

(vi) Maintenance charges, and

(vii) Octroi.

All these figures are provided at current prices. However, our main emphasis is on technical efficiency as defined by the minimum cost of delivering a KWh of energy at the bus-bar. It was therefore necessary to make the data comparable at constant prices. Price indices of different fuels have been prepared for each month and for each station (plant). The actual series of fuel cost is then deflated by the respective fuel price indices. Salaries and wages have also been deflated by an appropriate consumer price index. It would be evident from Appendix 5.A that there are differences in the size, technology and age of different units even within a given power plant. Hence, there may be differences in performance which can be explained

exclusively by these features[3]. However, the unit wise data was not available to us. The aggregate information utilized in the present analysis is subject to this inherent limitation.

5.6 OPERATIONAL PROBLEMS OF POWER PLANTS

The operational problems of most of the plants in our

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3. It may, however, be mentioned that some power plants in our sample have non-identical units which are manufactured by different companies with diverse technological constraints embodied in BTG sets. Bhusawal (II) has its plant size equal to the unit size whereas Panki has units of different sizes,e.g., (2x32 MW) and (2x110 MW) which are manufactured by Wagnor-Biro, Jugo Turbina and BHEL respectively. Similar technological diversity is encountered in Harduaganj (B) and (C), and Barauni. Durgapur coke-oven power plant belonging to Durgapur Power Projects Ltd. has experienced diversity of units with boiler efficiencies (in percentages) 88.75, 88.65 and 88.55 at 60, 80, and 100 percent load respectively. The boilers can sustain a maximum moisture content of 10 percent, ash content of 40 percent and volatile matter of 19-20 percent. Regarding fuel usage Trombay (Tata) uses fuel oil as its major fuel (e.g., low stock high sulphur (LSHS) or high stock high sulphur (HSHS) which are variants of residual fuel oil (RFO)) and natural gas and subsidiary fuels as minor fuels. Dhuvaran, another oil-fired power plant, consumes residual fuel il (major fuel) along with natural gas, light diesel oil, furnace oil, coal and lignite as ancillary fuels for ignition of the boiler. Neyveli Lignite Corporation has experimented with a lignite-fired boiler in contrast to the coal-fired one. The heating value of lignite is 550 BTU/16. It uses furnace oil and light diesel oil for appropriate ignition in different stages of production (i.e., energy generation).

sample have been documented by several earlier studies on steam electric power generation. Primarily, the problems are caused by the low grades of coal that have to be used and certain types of machine design and maintenance of the boilers and turbo-generators.

The majority of plants in our sample are coal-fired. The quality of coal not only controls the variable cost but also dictates to some extent the fixed cost. The capital costs, especially those of the boiler and turbo-generator, depend upon the type of coal. For higher grades of coal, i.e., coal having high calorific value, and lower moisture and ash contents, the capital costs are lower than for coal of lower grade which has low calorific value and high ash content. As a policy of conserving the limited resources of coking coals, the Government of India decided that large power plants should be designed for poorer grades of coal for which the ash content is not less than 35 to 45 percent[4]. On

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4. Many such instances have been reported in the literature. The low heat content of coal was the basic problem in the power plants at Nasik and Kothagudam (A). The Koradi, Paras and Bhusawal plants complain of high moisture content in the coal made available to them. See Sinha et al.(1963), and Joshi (1969) for details.

account of this policy, the costs of boiler fuel burning equipment, coal handling machinery and ash removal procedures, have gone up.[5]

Even when a plant is designed to burn coal, it cannot be introduced into the fuel cycle until the appropriate ignition temperature is attained. Hence, irrespective of the firing technique, there is a need for fuel oil for start up. It is also necessary to keep oil support along with coal until a stable furnace condition is established. Further, the high ash content of the coal used and inadequate ash handling cause unstable flame conditions. This necessitates purging the furnace in live condition. The use of fuel oil is indicated even for this operation.

The Singarani collieries supply coal to the Parli power plant. But this coal has a sand content and has been causing very fast erosion of the rollers in the P.F. mills, I.D. fan blades, and flue gas ducts. The rollers, fans and ducts have to be changed or replaced every three months.

Consider the other operational constraints encountered by representative plants in our sample. There are frequent failures of boiler tubes in the Ennore plant[6]. Considerable

5. For more details, see Rao and Rao (1972), and Chopra and Sampat (1972).

6. For detailed analysis, see Ahmed (1976), and Saptharishi (1978).

wear was found in the vapour pipes, vapour fans, and in the I.D. fans. The heavy flow of coal through vapour burners and the consequent high temperatures in the furnace result in tube punctures.

At high temperatures and pressures silica vaporises and later on re-condenses in the zones of low temperatures, particularly in the last stages of the turbine operations in the Badarpur plant[7]. During the start up of the unit, silica pickup is higher and to keep it under control, pressure has to be reduced and blow downs carried out. This involves addition of fresh water with the consequent loss of heat. This causes delay in the pickup of load during start up or reduction in load while the unit is already in operation.

In none of the boilers has it been feasible to maintain even 40 percent of rated load with only one I.D. fan working. Some plants have taken recourse to three I.D. fans. Improvement is still to be effected in the leakage of air into the boiler furnace and consequent difficulty in maintaining satisfactory furnace draft.

Thus, there is a great diversity both in terms of the technology and fuel choices available to the different plants in the sample. Similarly, each plant has certain problems

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7. See Bhasin (1976), and Doreswamy (1977) for details.

specific to itself. But it is difficult to assert that these specific features are dominant and that no other set of common factors can really explain the observed inefficiency.

APPENDIX 5.A

GENERATING CAPACITY OF PLANTS IN THE SAMPLE

Name of the Power Plant	Location (State)	Unit (MW)	Year of Insta-llation (commi-ssioning)	Total Installed Capa-city(MW)	Period of study From Month	Year	To Month	Year
Gurunanakdeb (Bhatinda)	Punjab	110 110 110 110	1974 1975 1976 1978	440.0	January	1980	March	1981
Faridabad	Haryana	60 60	1974 1976	120.0	January	1980	June	1981
Panipat	Haryana	110 110	1978 1979	220.0	April	1980	June	1981
Indraprastha	Delhi	36.6 62.5 62.5 62.5 60.0	1963 1966 1967 1968 1971	284.1	October	1979	March	1981
Badarpur (NTPC)	Delhi	100 100 100 210	1973 1974 1975 1978	510.0	January	1981	March	1982

Nasik	Maharashtra	140 140	1970 1971	280.0	January	1980	March	1981
Bhusawal(I)	Maharashtra	62.5	1968	62.5	January	1980	March	1981
Bhusawal(II	Maharashtra	210	1979	210.0	April	1980	March	1981
Paras	Maharashtra	30	1945	92.5	January	1980	March	1981
Koradi	Maharashtra	120 120 120 120 200	1972 1973 1975 1976 1978	680.0	January	1980	March	1981
Parli Vaijnatu	Maharashtra	60	1972	60.0	January	1980	March	1981
Trombay(Tata)	Maharashtra	62.5 62.5 62.5 150	1956 1957 1960 1965	337.5	October	1979	March	1981
Dhuvaran	Gujrat	3x63.5 63.5 2x140	1965 1964 1972	534.0	October	1979	March	1981
Ukai	Gujrat	2x120 200 200	1976 1977 1978	640.0	October	1979	June	1981
Kothagudam(A)	Andhra Pradesh	2x60 2x60	1968 1967	240.0	January	1980	March	1981

Kothagudam(B)	Andhra Pradesh	2x110	1975	220.0	April	1980	March	1981
Kothagudam(C)	Andhra Pradesh	2x110	1978	220.0	January	1980	March	1981
Ramagundam (B)	Andhra Pradesh	62.5	1965	62.5	January	1980	March	1981
Neyveli Lignite Corporation Ltd.	Tamil Nadu	50 3x50 50 50 100 100	1962 1963 1964 1965 1966 1968	600.0	April	1980	December	1981
Ennore	Tamil Nadu	60 60 110 110 110	1969 1971 1972 1973 1975	450.0	October	1979	March	1981
Basin Bridge	Tamil Nadu	30 30 30	1957 1967 1968	90.0	April	1980	March	1981
Panki	Uttar Pradesh	32 32 110 110	1967 1968 1976 1977	284.0	January	1980	June	1981
Harduaganj(B)	Uttar Pradesh	55 2x50 55	1966 1968 1973	210.0	April	1980	March	1981

24.	Harduaganj(C)	Uttar Pradesh	55 55 60	1975 1976 1978	170.0	April 1980	March 1981
25.	Barauni	Bihar	2x15 15 50 50	1963 1964 1969 1970	145.0	January 1980	March 1981
26.	Durgapur Power Projects Ltd.	West Bengal	2x30 75 75 75	- 1963 1964 1965	285.0	April 1980	March 1981

NOTE : Data for the recently commissioned 300 MW super thermal stations at Ramagundam (A.P.) and Singrauli (U.P.) are as yet not available.

APPENDIX 5.B

FORM CM-Q10 (REVISED)

CENTRAL ELECTRICITY AUTHORITY
COMMERCIAL DIRECTORATE
MINISTRY OF ENERGY
GOVERNMENT OF INDIA

For the quarter ending ______

MONITORING OF COMMERCIAL OPERATION OF THERMAL POWER STATIONS

COST ANALYSIS FOR POWER STATION

ame of Power Snt Stn.

Total installed capacity (KW)
Derated capacity (KW)

ARTICULARS	FIRST MONTH	SECOND MONTH	THIRD MONTH	TOTAL FOR QUARTER	VARIATION OVER PREV. QUARTER	CUMULA-TIVE FOR THE YEAR	RKS
1	2	3	4	5	6	7	8
(PART 1)							
. Peak Demand on the Station (KW)							
. Gross energy generated (MkWh)							
. Generation for KW IC (Installed capacity)							
. Load factor of the Station (percent)							

1	2	3	4	5	6	7	8
5. Consumption in auxiliaries (MkWh)							
6. Percentage of auxiliary consumption to generation							
7. Net generation (MkWh(2-5)							
8. Quantity of coal fuel used							
a) Coal (Metric tonnes)							
b) Furnace Oil(Kilo litres)							
c) LD Oil (KL)							
9. Fuel consumption							
a) Coal (Kg/kWh)							
b) Furnace Oil (KL/kWh)							
c) LD Oil (KL/kWh)							

1	2	3	4	5	6	7	8
10. Average calorific value (in Kilocalories/Kg)							
a) Coal							
b) Furnace Oil							
c) LD Oil							
d) Total :							
11. Total calories input X 10^{10}							
a) Coal							
b) Furnace Oil							
c) L.D. Oil							
d) Total							
12. Heat consumed (Heat rate) per kWh (in calories/kWh) (11d/2).							
13. Thermal efficiency(percent) (12/860)							

1	2	3	4	5	6	7	8
14. Cost of fuel (Rs.in lakhs)							
a) Coal							
b) Furnace Oil							
c) L.D. Oil							
d) Total :							
14(A) Central Excise Duty							
15. Average cost of fuel							
a) Coal (Rs.per tonne)							
b) Furnace Oil (Rs. per KL)							
c) L.D. Oil(Rs.per KL)							
16. Cost of fuel per kWh generated in Paise(14d/2)							
16(A) Cost of fuel per kWh generated in Paise(14d/2)							

1	2	3	4	5	6	7	8
17. a) Other Operational expenses excluding salaries, wages, etc. (Rs. in Lakhs)							
b) Cost per KWh (in Paise)							
18. a) Repairs and Maintenance charges excluding salaries and wages (Rs. in lakhs)							
b) Cost per KWh (in Paise)							
19. Total tunning cost per KWh (P) (16+17b+18b) (in Paise)							
20. Generation employees							
a) Technical staff (upto supervisory level)							
b) Workmen on operation							
c) Workmen repairs and maintenance							
d) Total							

1	2	3	4	5	6	7	8
21. a) No. of generation employees per MW of installed capacity							
b) Millicon K h generation per generation employee (2/20d)							

*The cost may be worked out on the basis of the latest average rates furnished by the Accounts Section and this shall include all incidental charges like transportation, excise duty, octroi etc. and on the basis of actual consumption during the period.

Sl.No.	Particulars	First month	Second month	Third month	Total for the quarter	variation over previous quarter	cumulative for the ueyear	Remarks
1	2	3	4	5	6	7	8	9
	PART II							
I.	Fixed Costs (Rs.lakhs)							
**1.	Salaries and Wages for Operation and Maintenance							
2.	Proportionate general establishment expenses							
3.	Depreciation							
4.	Rate of Interest(in Rs.lakhs)							
	a) Total loans outstanding:							
	i) at the beginning of the year							
	ii) at the end of the year							
	iii) average loans							

1	2	3	4	5	6	7	8
b) Total Interest payable							
c) Average rate of interest							
d) Original cost of the Plant including cost of intangible assets and general equipment							
e) Accrued depreciation							
f) Net cost of the Plant (d-e)							
g) Proportionate interest on the net cost of the Power Station (f x c)							
5. Total Fixed costs (Rs. lakhs) (1+2+3+4g)							
6. Fixed Cost per KW installed (Rs. in thousand) (5/Inst. Cap.)							
7. Fixed cost per kWh (Paise) (5/1 of Part-I)							

1	2	3	4	5	6	7	8
8. Additional Capital expenditure (Rs. lakhs) (if any)							
i) Commissioned Assets							
ii) Non-commissioned assets							

* Proportionate overheads may include :

a) Central office expenses directly allocable to generation

b) Remaining overhead expenses may be allocated on the basis of O and M expenses under generation, transmission, distribution, public lighting and consumer servicing (excluding cost of fuel, depreciation and interest)

c) Expenses allocated to generation may be apportioned to every station in proportion to the net cost of assets

d) Depreciation and interest may be worked out on annual basis and pro rata figures for the quarter indicated

e) Salaries and wages shall include, bonus, pension contributions, welfare expenditure, medical benefits etc.

f) If any other basis has been adopted, the details and justification therefore may please be furnished.

CHAPTER 6

DETERMINATION OF UNIT SIZE AND FUEL-MIX : CROSS-SECTION ANALYSIS

6.1 INTRODUCTION

Recall from Chapter 1 that power generation is said to be efficient if a KWh of energy is delivered at the minimum possible cost. Planning for this entails many choices at various levels of operations. As such inefficiency may manifest itself at every stage. One of the dimensions of inefficiency was referred to earlier as the system inefficiency. It represents the cost increase created by an inappropriate choice of installed capacity[1].

Before we can proceed further with the analysis,it is necessary to define the efficient choice of IC explicitly. In Chapter 4 it was noted that the optimal choice of IC should be capable of catering to the load on the system efficiently. In the context of the hierarchical form of organization outlined earlier it was felt that the decision would be based on the capital cost per kWh of energy.

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1. This statement was qualified in Chapter 4 as referring to inefficient choice of IC even if efficient plans were made for the utilization of a given IC. This aspect will be taken up presently.

However, such a choice does not depend on the load on the system. For, the total system demand on a Regional grid can be satisfied by a suitable number of plants each of which is of an efficient size from the viewpoint of average costs. Hence, it will be presumed that the efficient IC can be defined exclusively from the technical consideration of the minimum CC/kWh without any reference to the demands on the system.

The problem is then to define the best way of utilizing the information regarding CC/KWh in obtaining an estimate of the system inefficiency. Consider the possibility of estimating system inefficiency with respect to the choice of IC in each of the power plants by utilizing a time series analysis. This is impractical. For, the IC is relatively fixed over the short time period under consideration. Consequently, even on the basis of accepted accounting conventions, the short term variations in CC/kWh are mostly caused by the variations in CU only. Hence, attempts to utilize a time series estimate of the CC/kWh function would be futile.

However, if we consider the cross-section of power plants, they do differ considerably in size and even the capital cost components differ widely as IC varies. Hence, a cross-section analysis of the capital costs would reveal the optimal choice of IC more accurately. It was decided that this approach will be utilized.

This still leaves many choices. It is necessary to examine the alternatives so that the most appropriate concept of a cross-section can be identified. There are at least two choices :

(i) a monthly or a yearly average, and

(ii) averages for the peak load quarter.

A choice among these alternatives can be based on the following analysis.

Consider a plant with a given installed capacity. Its average monthly utilization, when connected to a grid, depends upon the resulting capital cost variation. It may be expected that the rate of capacity utilization increases monotonically with installed capacity especially because of its fuel efficiency and the general practice of merit-order loading of units. The average capacity utilization may vary systematically with installed capacity. Under such conditions, the monthly average capital cost per kWh may be mainly a function of capacity utilization rather than installed capacity and the results would be systematically biased as in the case of time series analysis of single plants. On the other hand, all plants are more or less loaded to their optimal capacity utilization at peak demand. Hence, if there are still any variations in capital cost per kWh, they must be due to variations in the installed capacity. A synthetic cross-section for the peak load quarter was therefore considered to be more useful to start with.

It is normally expected that the choice of installed capacity depends upon the expected peak load for every power plant. Only by making such an arrangement for the load in the area of operation of each power plant can the peak demand on the Regional grid be satisfied. It would therefore be necessary to view the optimality of the decisions regarding installed capacity in relation to the peak loads.

A perusal of the monthly load data for the various power plants indicated that peak demand occuredduring one of two quarters, viz., April-June 1980 or October-December 1980. A synthetic cross-section of the relevant information was therefore assembled for twenty one power stations which had mostly identical or similar technological characteristics. These details have been tabulated in Table 6.1.

6.2 THE DETERMINISTIC MODEL : CAPITAL COST EQUATION

Recall from Chapter 4 that there is an empirical judgement regarding the operation and maintenance (OM) costs before any estimation can be taken up. By definition, a deterministic framework is one where the planned availability rate of a power plant can in fact be delivered in the form of CU and power generation. It is also obvious that the OM costs would be related to the plant availability. As such, in the deterministic model, they would be fixed costs independent of the other operational decisions. Hence, the capital costs and OM costs are added to define the variable C_1. Thus, the

TABLE 6.1

SYNTHETIC CROSS-SECTION SERIES (APRIL-JUNE) 1980

Sl. No.	Name of the Plant	IC (MW)	CU (%)	PUR (%)	PLF (%)	FOR (%)	HR(KCal/ KWh)	CO(KCal/ KWh)	FO (KCal/ KWh)	LDO(KCal/ KWh)
1.	Indraprastha	284.0	63.98	91.55	67.09	19.89	3647.82	3396.77	251.05	-
2.	Nasik	280.0	64.96	100.00	79.58	10.43	2504.93	2447.96	39.57	1.57
3.	Parli Vaijnatu	60.0	92.57	100.00	95.76	4.95	3181.40	3162.64	14.23	4.54
4.	Ennore	450.0	41.10	82.36	59.75	14.74	3120.23	2714.18	379.16	26.88
5.	Barauni*	145.0	29.53	75.00	57.26	23.92	4067.70	3423.43	599.97	44.29
6.	Panki	284.1	51.91	100.00	59.55	34.03	3560.79	3404.40	34.87	121.51
7.	Ukai	640.0	44.15	99.17	55.83	29.09	3111.37	2647.16	450.56	13.65
8.	Koradi*	680.0	67.06	88.53	94.48	7.67	1540.66	1539.33	0.30	0.03
9.	Bhusawal(I)*	62.5	76.85	83.19	77.79	4.30	3154.17	3117.62	35.64	0.91
10.	Bhusawal(II)	210.0	46.53	81.57	27.86	30.82	2995.59	2508.21	437.42	49.96
11.	Paras	92.5	65.11	90.24	65.49	6.57	3092.36	3064.53	25.36	2.47
12.	Faridabad	120.0	36.95	40.45	23.29	6.11	4354.74	4019.18	229.26	106.30
13.	Panipat	220.0	37.42	96.11	42.44	43.46	3580.73	2784.26	593.41	203.06

Sl. No.	Name of the Plant	IC (MW)	CU (%)	PUR (%)	PLF (%)	FOR (%)	HR(KCal/ kWh)	CO(KCal/ kWh)	FO (KCal/ kWh)	LDO(KC kWh)
14.	Gurunanakdeb (Bhatinda)	440.0	39.22	75.28	55.51	24.76	3027.54	2819.51	187.71	20.31
15.	Kothagudam(A)	240.0	53.20	79.72	73.10	3.57	3111.38	3046.38	65.00	-
16.	Kothagudam(B)	220.0	27.66	66.67	57.24	30.70	3824.02	3546.19	277.83	-
17.	Kothagudam(C)	220.0	35.06	75.00	58.78	61.42	3491.98	3223.74	268.24	-
18.	Durgapur Power Projects Ltd.	285.0	29.27	64.29	63.21	15.58	3263.65	2996.21	267.43	-
19.	Basin Bridge	90.0	41.90	83.33	63.33	15.36	5376.36	4111.31	1265.05	-
20.	Harduaganj(B)	210.0	40.95	93.03	54.51	29.54	3784.48	3368.50	415.97	-
21.	Harduaganj(C)	170.0	53.36	81.34	56.54	29.71	3581.12	3446.36	134.76	-

*For the (October-December) 1980 Quarter

dependent variable in the first cost equation includes both capital costs and costs of operations and maintenance. Based on our earlier analysis, it now appears plausible to visualize the *ex ante* plans for IC and CU being drawn up on the basis of C_1 alone.

The estimated equation was of the following nature[2,3].

$$C_1 = 166.78 - \underset{(2.13)}{3.39(CU)} + \underset{(1.74)}{0.022\,(CU)^2} - \underset{(3.14)}{0.28(IC)}$$

$$+\underset{(2.53)}{0.00059(IC)^2} + \underset{(2.75)}{0.00018(CU)(IC)}$$

$$\bar{R}^2 = 0.99.$$

---

2. This turned out to be the best out of the four alternatives estimated.

3. An interpretation of the interaction term (CU) (IC) can be developed in the following manner : consider a simple specification of the capital cost equation in the form $CC/kWh = a+b(CU)+c(CU)(IC)$. Given an IC, the CC/kWh increases by $b+c(IC)$ if (CU) increases by one unit. Since it is generally expected that $b < o$ and $c > o$, this marginal increase would be negative for smaller values of (IC) but will become positive eventually. Hence, a negative c as well as some positive c allow the cost function to exhibit economies of scale. However, if $c < o$, a simultaneous increase in (IC) and (CU), beyond a certain value of (IC), gives rise to diseconomies of scale. This analysis is in consonance with that of Christensen and Greene (1976) though not identical with it.

The bracketed terms below each of the coefficients are the t-values associated with the corresponding coefficients.

From this equation, the optimum IC and CU can be computed as[4], IC = 223.92 MW, and CU = 77.94 percent. In order to assess the efficiency of the decision making process these estimates should be compared to the sample average of IC = 257.29 MW, and CU = 49.46 percent. It may appear from this comparison that the choice of IC is far closer to the efficient level compared to the CU itself.

But this inference is subject to a major qualification. For, in actual practice, the system is stochastic. At the most we may expect that the planning for plant availability would be efficient when the management has to cater to the peak load. The appropriate comparison is between the observed PUR of the peak quarter and the efficient CU computed. The observed PUR of 83.18 percent compares quite well with the optimal CU (77.94). It appears from this observation that the system level decisions are reasonably

---

4. The optimality computations were performed on the original DEC 1090 computer programming output before presenting all the estimates rounded off to two significant digits. The term optimal/optimum refers to satisfaction of both first-order and second-order conditions of cost minimization.

efficient[5].

6.3 DETERMINISTIC MODEL: THE FUEL COST EQUATION

The efficiency of the short-run operational decisions may be considered next. This can be developed from the fuel cost equation.

The neoclassical theory of production and costs, based on the standard duality theorem , postulates that the cost function depends primarily on the level of output and the relative prices of inputs. For, given a level of output, the changes in the factor proportions and costs are primarily dependent on the relative price combinations that occur in practice. In the present study, all the time series are deflated by appropriate price indices and hence they will not affect the fuel cost equations.

However, note that, with given factor prices the factor proportions themselves may not remain constant. For, the nature of the production function may be such that the expansion paths are not linear. Whenever this happens the factor proportions would enter the specification of the

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5. In the context of other large investments in the public sector, it was often remarked that careful and efficient choices are made whenever the cost implications are significant. Even here we find that planning for the largest cost component may be quite efficient.

cost function along with the level of output itself. Such choices of fuel-mix, if they exist, would constitute the major technological choice among the fuel-mix alternatives for a given level of output and relative factor prices.

Before proceeding with the specification and estimation of the fuel cost equation, it would be beneficial to examine the hypothesis of non-linear expansion paths. We constructed Tables 6.2 and 6.3 accordingly. From these, and the accompanying Figures 6.1 and 6.2, it may be noted that FO/CO does not remain invariant with increases in IC and average energy generation. In fact, it may be suggested that there is a decreasing relationship in both the diagrams[6]. Consequently, the expansion path is not linear and the fuel-mix combinations will have to be introduced in the cost function explicitly.

The most appropriate fuel-cost equation turned out to be

$$C_2 = -83.31 + \underset{(2.40)}{0.034(HR)} + \underset{(2.23)}{199043.91(1/HR)}$$

$$\underset{(1.76)}{-0.00018(HR)(CU)} - \underset{(1.74)}{520.04(FO/CO)} + \underset{(1.74)}{2146.60(FO/CO)^2}$$

$$\underset{(1.88)}{-888.92(LDO/CO)} + \underset{(1.88)}{38561.03(LDO/CO)^2}$$

$\bar{R}^2 = 0.91$

---

6. This may be viewed as a tendency rather than a rigorous functional relationship. For, we find that some plants are not on this negatively sloped trend. This may be due to size of units, difference in technology and so on. For our purposes the absence of the invariance is sufficient.

TABLE 6.2

INSTALLED CAPACITY, ENERGY GENERATION AND HEAT RATE : COMPARISON ACROSS POWER PLANTS

Sl. No.	Name of the Power Plant	IC (MW)	Average Generation (MkWh)	Heat Rate Kcal/kWh
1.	Parli Vaijnatu	60.0	37.61	3286.31
2.	Bhusawal (I)	62.5	33.27	3321.00
3.	Ramagundam (B)	62.5	31.23	2787.35
4.	Basin Bridge	90.0	27.37	4820.22
5.	Paras	92.5	43.76	3300.72
6.	Faridabad	120.0	33.62	3704.14
7.	Barauni	145.0	27.26	4262.99
8.	Harduaganj (C)	170.0	41.25	3456.51
9.	Harduaganj (B)	210.0	52.54	3772.90
10.	Bhusawal (II)	210.0	66.08	3229.20
11.	Kothagudam (B)	220.0	34.38	3703.09
12.	Kothagudam (C)	220.0	51.99	3301.63
13.	Panipat	220.0	54.69	4066.57
14.	Kothagudam (A)	240.0	87.80	3114.92
15.	Nasik	280.0	130.50	2531.32
16.	Indraprastha	284.1	132.46	3461.48
17.	Panki	284.0	105.68	3629.40
18.	Durgapur Power Projects	285.0	59.37	3239.47

contd ...

TABLE 6.2 (contd ...)

Sl. No.	Name of the Power Plant	IC (MW)	Average Generation (MKWh)	Heat Rate Kcal/kWh
19.	Trombay (Tata)	337.5	168.88	2978.67
20.	Gurumanakdeb	440.0	116.45	3081.88
21.	Ennore	450.0	120.89	3236.94
22.	Badarpur	510.0	185.30	3417.32
23.	Dhuvaran	534.0	274.51	2785.52
24.	Neyveli Lignite Corp. Ltd.	600.0	267.71	3405.18
25.	Ukai	640.0	175.05	3048.34
26.	Koradi	680.0	293.26	2217.92

TABLE 6.3

AVERAGE ENERGY GENERATION VS FUEL-MIX : CROSS-SECTION OF PLANTS

Sl. No.	Name of the Power Plant	Average generation (MkWh)	FO/CO	LDO/CO	NG/OIL	CO/RFO	FO/RFO	NG/RFO	LDO/RFO	LIG/RFO	FO/LIG	LDO/LIG
1.	Parli Vaijnatu	37.61	0.0038	0.0013	-	-	-	-	-	-	-	-
2.	Bhusawal(I)	33.27	0.02	0.0007	-	-	-	-	-	-	-	-
3.	Ramagundam(B)	31.23	0.0081	0.0017	-	-	-	-	-	-	-	-
4.	Basin Bridge	27.37	0.23	-	-	-	-	-	-	-	-	-
5.	Paras	43.76	0.0064	0.00043	-	-	-	-	-	-	-	-
6.	Faridabad	33.62	0.06	0.018	-	-	-	-	-	-	-	-
7.	Barauni	27.26	0.16	0.012	-	-	-	-	-	-	-	-
8.	Harduaganj(C)	41.25	0.052	-	-	-	-	-	-	-	-	-
9.	Harduaganj(B)	52.54	0.14	-	-	-	-	-	-	-	-	-
10.	Bhusawal(II)	66.08	0.11	0.011	-	-	-	-	-	-	-	-

contd ...

	Average generation (MkWh)	FO/CO	LDO/CO	NG/ OIL	CO/ RFO	FO/ RFO	NG/ RFO	LDO/ RFO	LIG/ RFO	FO/ LIG	LDO/LIG
11. Kothagundam(B)	34.38	0.10	-	-							
12. Kothagudam(C)	51.99	0.12	-	-							
13. Panipat	54.69	0.27	0.048	-							
14. Kothagudam(A)	87.80	0.017	-	-							
15. Nasik	130.50	0.019	0.01	-							
16. Indraprastha	132.46	0.059	-	-							
17. Panki	105.68	0.011	0.032	-							
18. Durgapur Power Projects	59.37	0.10	-	-							
19. Trombay(Tata)	168.88	-	-	0.38							
20. Gurunanakdeb	116.45	0.058	0.011	-							
21. Ennore	120.89	0.091	0.0066	-							
22. Badarpur	185.30	0.078	0.0018	-							
23. Dhuvaran	274.51	-	-	-	0.11	0.19	0.059	0.016	0.021	-	-
24. Neyveli Lignite Corp.Ltd.	267.71	-	-	-	-	-	-	-	-	0.11	0.0056
25. Ukai	175.05	0.18	0.0069								
26. Koradi	293.26	0.021	0.0092								

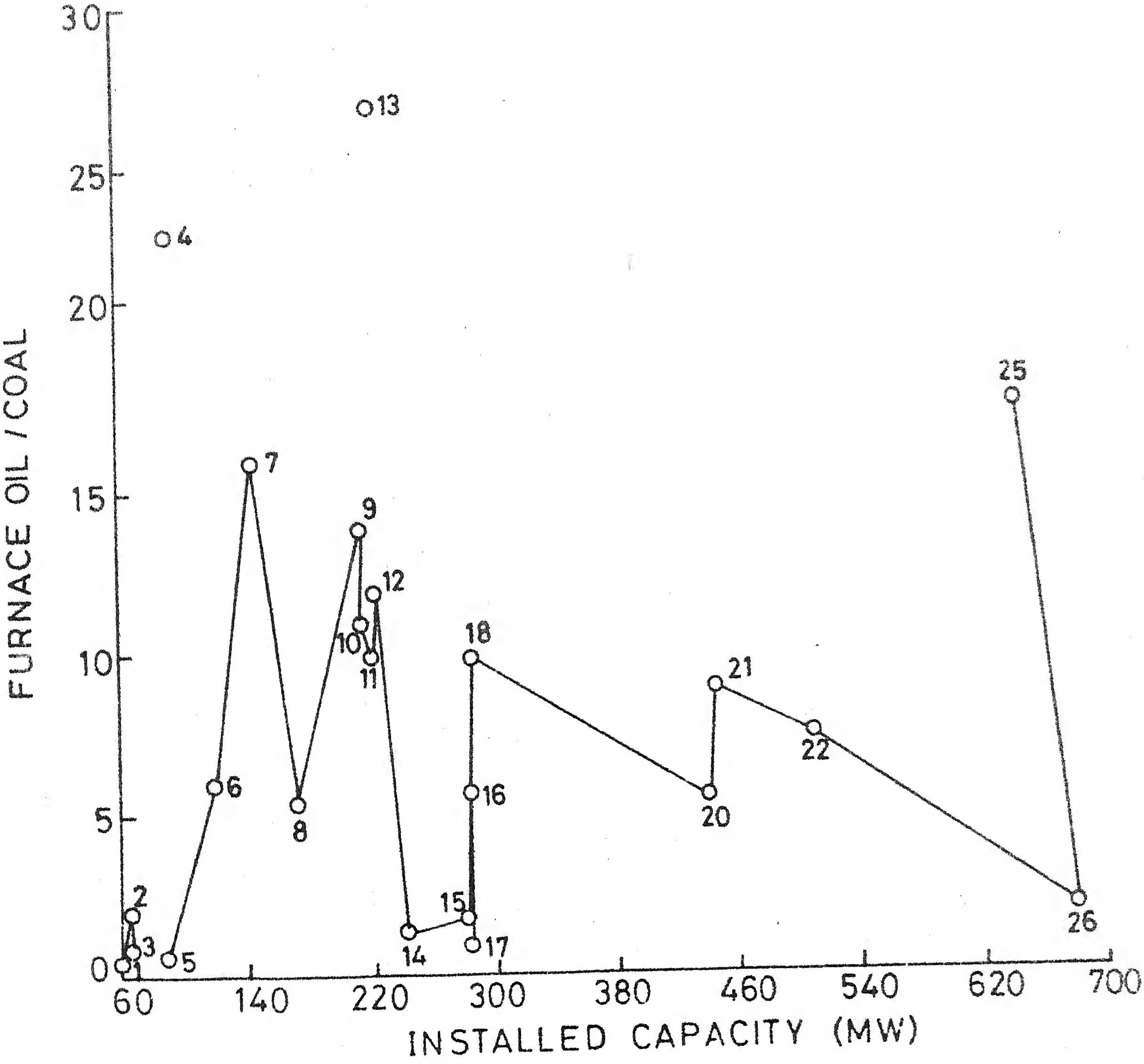

FIG. 6·1 INSTALLED CAPACITY (IC) VS FURNACE OIL/COAL (FO/CO)

Note : The serial nos. of the power plants correspond to those in Tables 6·2 - 6·3

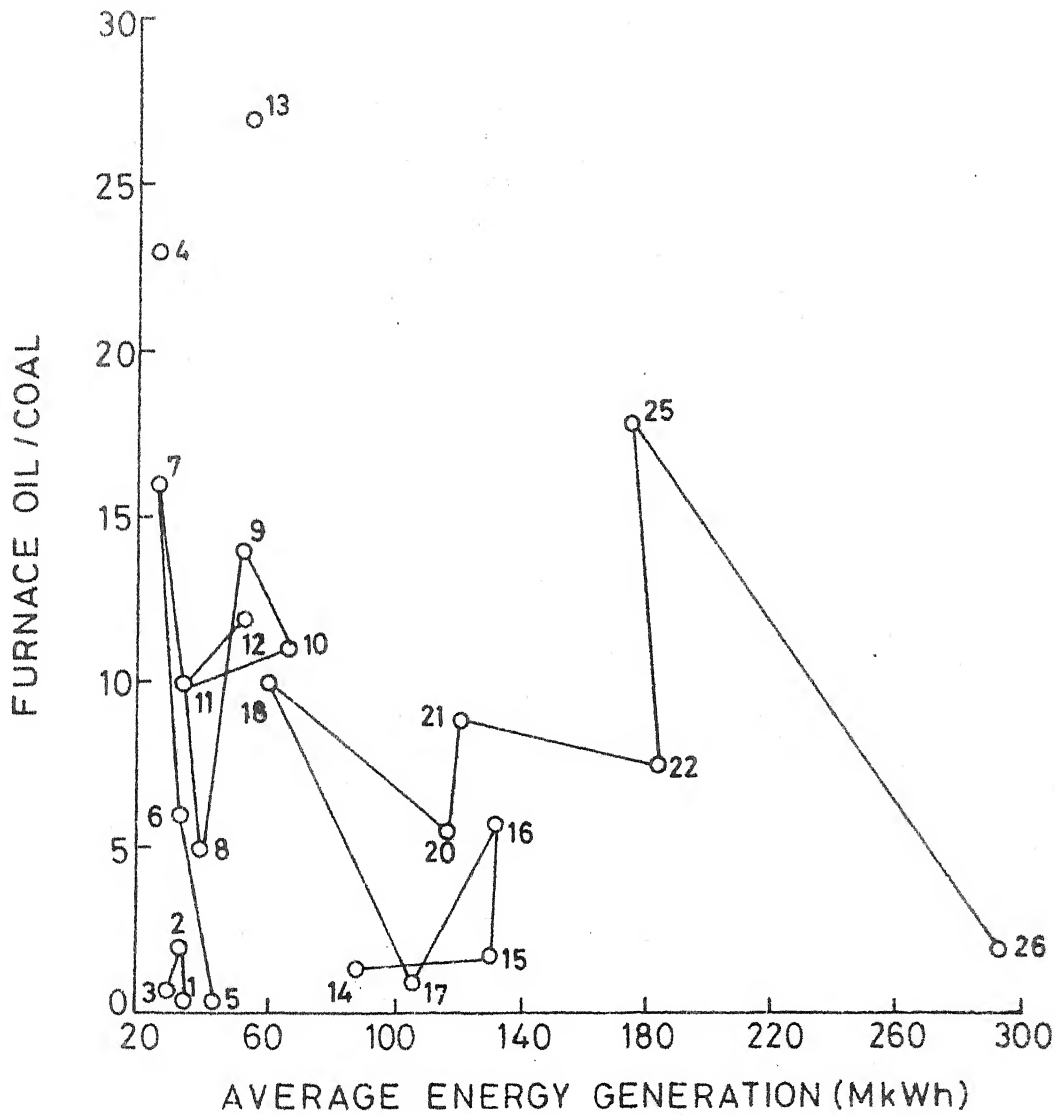

FIG. 6.2 AVERAGE ENERGY GENERATION VS FURNACE OIL / COAL (FO / CO)

where C_2 is deflated fuel-cost per kWh,

HR is heat rate (Kcal/kWh),

FO is furnace oil (Kcal/kWh),

CO is coal (Kcal/kWh), and

LDO is light diesel oil (Kcal/kWh)

From the analytical descriptions of Chapter 4,it is apparent that the observed fuel cost figures may contain aspects of planning inefficiency as well as operational inefficiency. The most efficient choices of HR and fuel-mix are obtained from the above equation by substituting the efficient value of CU (i.e., 77.94). For this choice, the corresponding optimal values of HR and fuel-mix are the following :

HR = 3204.23, CO = 2828.95, FO = 342.67, LDO = 32.61, FO/CO = 0.12, LDO/CO = 0.011.

However, these values are attainable only if there is no planning inefficiency or operational inefficiency.

The effect of planning inefficiency on the choice of HR and fuel-mix can be exhibited by computing the corresponding values for the observed CU (namely 49.46). Such a calculation results in HR = 2816.19, CO = 2486.36, FO = 301.17, LDO = 28.66, FO/CO = 0.12, and LDO/CO = 0.011.

It is to be noted that in both the cases (FO/CO) and (LDO/CO) are the same ,i.e., 0.12 and 0.011 respectively. The

efficiency of fuel choice, i.e., furnace oil and light diesel oil in relation to coal, is indicated by comparing the observed magnitudes of FO/CO (0.092) and LDO/CO(0.0092) with the efficient values.

These results indicate that there is operational inefficiency even at peak loads and this may not change significantly whatever may be the magnitude of planning inefficiency. All these results are exhibited in a summary form in Tables 6.4 and 6.5.

As in the case of the estimation of system inefficiency, this result is valid only for the peak quarter. Similarly, since no consideration is given to the stochastic variations which are ingrained in the production process, the observed PUR rather than CU would have been the appropriate variable for comparison. When this is done, the degree of inefficiency at peak load appears to be quite small. However, no definitive statement would be possible until we examine the stochastic variant of the model.

Further, it may be generally expected that the planning and operational inefficiencies may be higher at lower loads. Stated somewhat differently, the monthly variations would be far more pronounced compared to what is observed for the peak quarter. A study of this aspect necessitates time series analysis.

TABLE 6.4

SYNTHETIC CROSS-SECTION : AVERAGES

IC(MW)	257.29
CU (percentage)	49.46
HR (Kcal/kWh)	3397.91
PLF (percentage)	61.35
PUR (percentage)	83.18
FOR (percentage)	21.27
CO (Kcal/kWh)	3085.14
FO (Kcal/kWh)	284.42
LDO (Kcal/kWh)	28.36
FO/CO	0.092
LDO/CO	0.0092

NOTE : These figures are averages for twenty one coal-fired power plants. They have been computed from Table 6.1.

TABLE 6.5

DETERMINISTIC MODEL : RESULTS

IC (MW)	CU (%)	HR (Kcal/kWh)	CO (Kcal/kWh)	FO (Kcal/kWh)	LDO (Kcal/kWh)	FO/CO	LDO/CO
223.92	77.94	3204.23	2828.95	342.67	32.61	0.12	0.011
257.29	49.46*	2816.19	2486.36	301.17	28.66	0.12	0.011

*Observed value of CU.

6.4 STOCHASTIC MODEL

When the production process is subject to random variations, the output delivered invariably differs from planned level of plant availability. Further, any such unexpected breakdown necessitates additional repairs and OM costs over and above the levels which a plant's PUR entails. Fundamentally, the repair and OM costs can no longer be treated on par with the capital costs. Hence, we transferred this component from capital cost to the variable cost and designated the rest of the capital cost component as C_3.

It may also be expected that the decision maker would take the possibility of forced outages and the randomness of the plant load factor into account in determining the optimal IC and CU. For, a given expected FOR may be compensated by (i) increasing CU with a given IC, (ii) increasing IC with a given CU, or (iii) choosing a smaller IC as well as CU so that the effect of a breakdown is localized. The relative efficiency of these choices can be assessed from the capital cost equation if it incorporates aspects of exogenous randomness as well as system-wide decision choices.

Past literature made elaborate attempts to either measure or postulate probability distribution for FOR and PLF, and try to evaluate IC and CU on some expected value criteria.

We feel that a far more direct and simple formulation would be to introduce the average variables in the C_3 equation and exhibit the cost trade-offs which will determine the efficient choices of IC and CU.

With these considerations in perspective, the capital cost equation was estimated in the following form :

$$C_3 = 305.11 - \underset{(1.89)}{3.68(CU)} + \underset{(1.84)}{0.025(CU)^2} - \underset{(2.62)}{1.095(IC)}$$

$$+ \underset{(2.13)}{0.00095(IC)^2} + \underset{(2.21)}{0.029(IC)(FOR)} + \underset{(2.23)}{0.00020(IC)(CU)}$$

$$- \underset{(2.47)}{0.0054(IC)(PUR)}$$

$\bar{R}^2 = 0.94.$

As expected, the cross terms (IC)(FOR) and (IC)(CU) have positive coefficients while (IC)(PUR) has a negative coefficient. Generally, a larger FOR increases capital cost/kWh for a given IC. But an increase in PUR for a given IC diminishes C_3. For, the more the planned utilization rate, the easier it becomes to spread the capital cost over a larger volume of energy produced from a given IC[7].

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7. The interpretation of the positive coefficient for (IC)(CU) carries over from foot-note 3 of Section 6.2.

It will be postulated, as before, that capital cost considerations alone play an important role in the determination of the optimal IC and CU. For observed values of FOR (21.27), PLF (61.35), and PUR (83.18), the optimum values of IC and CU can be computed as 246.21 MW and 79.95 percent respectively. These figures are even closer to the observed averages in comparison to those obtained in the deterministic model.

The decision process at the operational level can now be conceptualized as consisting of (i) a choice of PUR which can deliver the desired CU *ex post*, and (ii) choices of HR and fuel-mix as before. But this will be done in two distinct steps. For, once a PUR is chosen, certain costs of repair and OM (operation and maintenance) cannot be altered.

The repair cost and OM costs which are subject to variation of PLF and FOR, are now added to the fuel cost to obtain C_4 per kWh. The estimated equation takes the form :

$$C_4 = 111.76 - \underset{(2.38)}{2.62(PUR)} + \underset{(2.34)}{0.017(PUR)^2} - \underset{(2.24)}{0.0034(PUR)(PLF)}$$

$$+\underset{(1.96)}{0.00076(PUR)(FOR)}$$

$\bar{R}^2 = 0.91.$

It may be noted that as FOR increases for a given PUR, C_4/KWh increases (i.e., the coefficient of the cross term (PUR)(FOR) is positive) and as PLF increases for a given PUR, C_4/KWh diminishes (i.e., the coefficient of the interaction term (PUR)(PLF) is negative). This is in consonance with expectations because any increase in PLF (i.e., the ratio of average demand or load to maximum demand or load) makes the system efficient by reducing the variable cost per kWh.

At the observed values of PLF (61.35) and FOR (21.27), the optimum choice of PUR becomes 80.43. The optimal IC and CU, computed from the C_3 equation corresponding to the optimal PUR (80.43), are 246.24 MW and 79.66 percent respectively. There is an excellent correspondence between the optimal CU and the observed PUR (83.18) even in the stochastic case. Primarily, this result indicates that with adequate prior planning, very close to planned availability,power can in fact be delivered even when the system is subject to stochastic production losses. The significant deviation of the observed CU from the optimal CU indicates the existence of far more pronounced operational inefficiency as compared to the planning inefficiency.

As noted in Chapter 4, Section 5, the fuel cost equation is common to both the stochastic and the deterministic models. Given the variations in the PUR and CU, that equation may again

be utilized to determine the HR and fuel-mix combinations. Proceeding sequentially, it can be verified that the C_4 equation gives an optimal PUR of 80.43 and the corresponding CU computed from the C_3 equation would be 79.66. These figures are quite close to the observed PUR of 83.18 and the corresponding CU which can be estimated to be 79.95. The optimal HR and fuel-mix for these two values of CU can be exhibited as follows : HR = 3230.75, CO = 2852.37, FO = 345.51, LDO = 32.88, FO/CO = 0.12, LDO/CO = 0.011 at optimum CU (79.66), and HR = 3235.28, CO = 2856.37, FO = 345.99, LDO = 32.92, FO/CO = 0.12, LDO/CO = 0.011 at optimum CU (79.95).

From these calculations, it appears that even the HR and fuel-mix choices of the operational management correspond closely to the optimum values. Further, the optimal HR is quite comparable to the name-plate HR.

However, some possibilities of substituting furnace oil and light diesel oil for coal are indicated when we compare the optimal values with observed magnitudes. For, we have CO (observed) 3085.14, CO(optimal) 2856.37, FO (observed) 284.42, FO(optimal) 345.99, LDO (observed) 28.36, LDO (optimal) 32.92.

Table 6.6 summarizes the results so far obtained from the stochastic model. However, it should be reiterated that the above results are valid only for the peak load quarter and no further information can be obtained until a time series analysis is carried out for each plant.

6.5 COST IMPLICATIONS OF INEFFICIENCY

Upto this point inefficiency was empirically demonstrated only in terms of the physical choices of inputs. However, it was clear from the outset that the degree of inefficiency will have to be measured in terms of the cost implications of the various physical choices. The purpose of the present Section is to explore this dimension in some detail.

Consider the deterministic model first. The empirical estimates turned out to be the following :

(i) Observed CC/KWh = 7.5 paise

System inefficiency = 0.65 paise

Capital cost component of planning inefficiency = 15.42 paise.

(ii) Observed FC/KWh = 26.0 paise

Fuel-cost component of planning inefficiency = 15.25 paise

Operational inefficiency = 4.51 paise.

TABLE 6.6

STOCHASTIC MODEL : RESULTS

IC (MW)	PUR (%)	CU (%)	HR (Kcal/kWh)	CO (KCal/kWh)	FO (Kcal/kWh)	LDO (Kcal/kWh)	FO/CO	LDO/CO
246.24	80.43	79.66	3230.75	2352.37	345.51	32.88	0.12	0.011
246.21	83.18*	79.95	3235.28	2856.37	345.99	32.92	0.12	0.011

*Observed value of PUR.

It would be noted from this that the system inefficiency resulting from the choice of IC is minimal. The planning inefficiency, even if it was not the dominant feature when physical magnitudes were compared, has a very large cost impact. The operational inefficiency is a substantial quantity of the order of 13 to 14 percent of the total cost of generating a KWh of energy.

However, the planning inefficiency measurement is highly unreliable . The primary reason for this is the significant difference between the optimal and observed average CU's. As we noted in the earlier Sections, the appropriate comparison in the cross-section would be between the optimal CU and the observed PUR. When this adjustment is made the above discrepancy is eliminated and operational inefficiency turns out to be the largest contribution.

The approach to the measurement of inefficiency proved to be far more acceptable when the appropriate managerial adjustments to stochastic variations in the production process are taken into account. The following estimates were obtained from the stochastic model :

(i) Observed CC/KWh = 7.5 paise

System inefficiency = 0.55 paise

Capital cost component of planning inefficiency = 3.92 paise

(ii) Observed FC/kWh = 26.0 paise

Fuel cost component of planning inefficiency = 0.25 paise

Operational inefficiency = 4.51 paise.

It may generally be concluded that the operational inefficiency has the largest impact on the average total cost/kWh of energy generation. But relative to CC/kWh, the capital cost component of planning inefficiency is very high. Reducing FOR and/or accounting for it, for the extent it can be anticipated on the basis of past experience, in making plans for power generation appear to be warranted in the interest of efficient production.

We will endeavour to examine these aspects of inefficiency in the time series analysis of plant level data since that is the more practical dimension from an operational viewpoint. These results will be examined in Chapters 7 and 8.

6.6 BRIEF SUMMARY

It is therefore clear from the above analysis that the IC itself is reasonably well-chosen and does not create any undue increases in production cost[8].

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8. Two qualifications are in order. An optimal plant size of 250 MW is too small if there are two or more units in the plant. Optimality of the unit size could not be checked due to lack of data. It would be useful to do this analysis as and when it is possible. Secondly, the sample did not have the 300 MW super thermal stations which have been recently commissioned at Obra, Singrauli, and Ramagundam. It is possible that this has created a downward bias in the estimation of the optimal IC in the present study.

Secondly, the optimal planned utilization rate is quite comparable to optimal capacity utilization rate. However, the actual CU is far below the optimal level primarily due to the forced outages and the planning inefficiency which does not appear to account for it appropriately. Thirdly, the level of operational inefficiency is substantial when the choices of HR and fuel-mix are considered. But due to the relative flatness of the cost curves they did not get translated into equally large magnitudes of inefficiency when measured in terms of costs.

The planning and operational inefficiency aspects can be pursued more fruitfully only when we consider plant level operations. Time series analysis of these dimensions will be presented in Chapters 7 and 8.

APPENDIX 6.A

OTHER INDIAN STUDIES ON SIZE DECISIONS

There have been several studies on the determination of the optimal size of installed capacity. The methodology of these models as well as the results differ somewhat from those presented in this Chapter. It may be worthwhile to present a brief contrast of these approaches.

Pandit et al. (1971) examined the selection of unit sizes from the viewpoint of system economics. Their method was aimed at determining the maximum load for a unit if a designated level of reliability had to be satisfied. They established that power systems in India will require 500 MW size thermal units by 1975 and 800 MW units by 1979.

In contrast, Ojha (1972) advocated manufacture and installation of 500 to 600 MW units by 1980 and optimal sizes of 1000 to 1200 MW by the year 1990. The maximum unit size to the total maximum demand of a Regional inter-connected system on an average comes to 5.5 percent. This would mean that under the existing system conditions in the Regions (Northern, Western, Southern, Eastern, and North-Eastern) for an outage condition of 3 percent a net reserve capacity of about 15 percent would be required. However, Ojha prescribed

an enlargement of the unit size by about 3 to 4 percent. This, as is evident, is not in consonance with his analysis.

The Atomic Energy Commission, with the collaboration of the Tata Institute of Fundamental Research and the concerned State Electricity Boards (cf. Narasimhan et. al (1970)), carried out a study of the optimum mix of generating capacities for various power stations/plants in the Northern Region (i.e., Rajasthan, U.P., Punjab, Haryana, Delhi, Jammu and Kashmir). They maintain that 200 MW turbo-generator sets are optimal.

That the optimal installed capacity depends upon the demand conditions has often been emphasized by models such as in Manne (1967) and related work which developed subsequently[9].

But the emphasis in our study was on the technological optima based on average cost minimization alone. The reason is simply that each of the plants does not cater to any specific load or demand. Instead, they are connected to the grid and all the plants of a given grid would together have to satisfy the demand on the system.

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9. See Gately (1971), Mukherjee (1974), Lahiri (1977), and the World Bank Country Study: INDIA - Economic Issues in the Power Sector (1979), pp. 151-157, for necessary details.

There is another dimension implicit in analysis of the kind reported. These demand related models assume that economies of scale are not exhausted over a wide range of IC. But this does not appear to be valid on empirical grounds. Hence, even these approaches should take this into account. But unfortunately, such models did not adequately take these factors into consideration. Hence, the optimal size calculations of these other studies are erroneous.

Primarily, the argument of this Appendix points out two important dimensions of the problem. Firstly, there is a necessity to distinguish between the unit size and plant size. As the demand for energy increases, there may be a necessity to increase plant size by increasing the number of units of the optimal size. The unit size itself is limited by the technological constraints on the economies of scale. Secondly, when the power plants are connected to a grid, the demand on the system is bound to be larger than the optimal unit size. This reinforces the earlier observations. Most of the studies referred in this Appendix confused the issue by not making this distinction in proper manner.

CHAPTER 7

DETERMINISTIC MODEL : TIME SERIES ANALYSIS

7.1 INTRODUCTION

From the cross-section analysis of thermal power plants, we observed that

(i) the observed average of the installed capacity is quite close to the optimal value obtained by minimizing the capital cost (CC/kWh),

(ii) the optimal planned utilization rate is reasonably close to the optimal capacity utilization rate for the quarter in which the peak load occurs, and

(iii) the operational inefficiency is pronounced and this does not reduce significantly whatever may be the magnitude of the planning inefficiency.

It may be, generally, expected that the planning and operational inefficiencies will be greater, than those indicated for the peak load quarter by the cross-section analysis, when monthly fluctuations in average load on the system are taken into account. Hence, it is necessary to examine the efficiency of the operational decisions over time for each plant.

The primary purpose of the present chapter is to present in some detail the empirical experiences of the time series analysis at the plant level. For purposes, of expositional clarity, we confine ourselves to the deterministic model in the present chapter.

7.2 THE CAPITAL COST EQUATION

It would be expedient to consider the estimated equations one at a time. In the present section we shall consider the capital cost (CC/kWh) equation.

Fundamentally, the specification of this equation in time series differs from its counterpart in the cross-section analysis. For, from the vantage point of the manager at the planning level, the installed capacity (IC) is no longer a decision variable. Instead, it is fixed over the short time horizon under consideration. Consequently, the managers at this level can be conceptualized as having capacity utilization alone as a choice variable[1].

The estimated capital cost (CC/kWh) equations are shown in Table 7.1, The dependent variable C_1 is the sum of capital cost, operations and maintenance (OM) costs, and repair costs per KWh. In the absence of production and demand uncertainties, the OM and repair costs are almost

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1. The distinction between PUR and CU is not relevant in the deterministic formulation.

TABLE 7.1

DETERMINISTIC MODEL : SYSTEM OF NON-LINEAR EQUATIONS ESTIMATED FOR POWER PLANTS

<u>GURUNANAKDEB (BHATINDA) :</u>

(JANUARY 1980 - MARCH 1981)

$$C_1 = 57.72 - \underset{(4.49)}{1.68}(CU) + \underset{(3.17)}{0.015}(CU)^2, \quad \bar{R}^2 = 0.93, \quad DW = 1.75$$

$$C_2 = -111.66 + \underset{(2.55)}{0.031}(HR) + \underset{(2.79)}{185958.61}(1/HR)$$

$$- \underset{(7.84)}{0.00017}(HR)(CU) - \underset{(2.84)}{63.30}(FO/CO) + \underset{(2.63)}{270.49}(FO/CO)^2, \quad \bar{R}^2 = 0.89,$$

$$DW = 2.52$$

<u>FARIDABAD :</u>

(JANUARY 1980 - JUNE 1981)

$$C_1 = 97.41 - \underset{(8.18)}{4.31}(CU) + \underset{(6.10)}{0.05}(CU)^2, \quad \bar{R}^2 = 0.87, \quad DW = 2.20$$

$$C_2 = -988.89 + \underset{(4.14)}{0.19}(HR) + \underset{(3.01)}{1468492.9}(1/HR) - \underset{(2.23)}{0.00062}(HR)(CU)$$

$$+ \underset{(1.45)}{395.75}(LDO/CO) + \underset{(1.69)}{0.14}(1/(LDC/CO)), \quad \bar{R}^2 = 0.85, \quad DW = 1.70$$

<u>PANIPAT :</u>

(APRIL 1980 - JUNE 1981)

$$C_1 = 52.86 - \underset{(12.12)}{1.60}(CU) + \underset{(7.66)}{0.015}(CU)^2, \quad \bar{R}^2 = 0.99, \quad DW = 2.33$$

$$C_2 = -124.08 + \underset{(1.65)}{0.029}(HR) + \underset{(1.83)}{282631.37}(1/HR) - \underset{(4.12)}{0.00015}(HR)(CU)$$

$$- \underset{(2.16)}{16.60}(FO/CO) + \underset{(2.73)}{22.58}(FO/CO)^2, \quad \bar{R}^2 = 0.90, \quad DW = 2.19$$

INDRAPRASTHA :

(OCTOBER 1979 - MARCH 1981)

$$C_1 = 48.57-\underset{(2.51)}{0.89}(CU)+\underset{(2.12)}{0.0051}(CU)^2, \quad \bar{R}^2 = 0.97, \quad DW = 0.63$$

$$C_2 = -4.55+\underset{(1.62)}{0.0063}(HR)+\underset{(1.80)}{51565.15}(1/HR)-\underset{(6.29)}{0.000022}(HR)(CU)$$
$$-\underset{(2.28)}{153.28}(FO/CO)+\underset{(2.78)}{682.17}(FO/CO)^2, \quad \bar{R}^2 = 0.88, \quad DW = 2.21$$

BADARPUR (NTPC) :

(JANUARY 1981 - MARCH 1982)

$$C_1 = 22.44-\underset{(7.25)}{0.51}(CU)+\underset{(5.22)}{0.0038}(CU)^2, \quad \bar{R}^2 = 0.96, \quad DW = 2.40$$

$$C_2 = -11.69+\underset{(2.09)}{0.0055}(HR)+\underset{(2.76)}{35139.19}(1/HR)-\underset{(12.57)}{0.000035}(HR)(CU)$$
$$-\underset{(4.40)}{54.51}(FO/CO)+\underset{(6.00)}{183.71}(FO/CO)^2, \quad \bar{R}^2 = 0.98, \quad DW = 2.61$$

NASIK :

(JANUARY 1980- MARCH 1981)

$$C_1 = 16.04-\underset{(13.45)}{0.32}(CU)+\underset{(9.10)}{0.0019}(CU)^2, \quad \bar{R}^2 = 0.99, \quad DW = 1.14$$

$$C_2 = 2688.49-\underset{(2.13)}{2.33}(HR)+\underset{(2.13)}{0.0005}(HR)^2+\underset{(10.69)}{0.000085}(HR)(CU)$$
$$-\underset{(1.60)}{45.96}(LDO/CO)+\underset{(2.77)}{3046.62}(LDO/CO)^2, \quad \bar{R}^2 = 0.98, \quad DW = 2.24$$

BHUSAWAL(I) :

(JANUARY 1980 - MARCH 1981)

$$C_1 = 47.01 - \underset{(7.21)}{0.96}(CU) + \underset{(5.21)}{0.006}(CU)^2, \quad \bar{R}^2 = 0.93, \quad DW = 0.99$$

$$C_2 = -649.05 + \underset{(2.90)}{0.1}(HR) + \underset{(2.98)}{1081442.0}(1/HR) + \underset{(1.96)}{0.000012}(HR)(CU)$$
$$-\underset{(2.62)}{197.24}(FO/CO) + \underset{(2.92)}{2984.57}(FO/CO)^2, \quad \bar{R}^2 = 0.94, \quad DW = 0.76$$

BHUSAWAL (II) :

(APRIL 1980 - MARCH 1981)

$$C_1 = 18.38 - \underset{(3.00)}{0.51}(CU) + \underset{(2.28)}{0.0043}(CU)^2, \quad \bar{R}^2 = 0.93, \quad DW = 0.76$$

$$C_2 = 5.89 + \underset{(1.76)}{0.0032}(HR) + \underset{(1.85)}{22516.93}(1/HR) - \underset{(1.62)}{0.0000049}(HR)(CU)$$
$$-\underset{(1.73)}{14.03}(FO/CO) + \underset{(1.82)}{24.06}(FO/CO)^2, \quad \bar{R}^2 = 0.94, \quad DW = 2.00$$

PARAS :

(JANUARY 1980 - MARCH 1981)

$$C_1 = 18.38 - \underset{(3.15)}{0.41}(CU) + \underset{(2.79)}{0.0028}(CU)^2, \quad \bar{R}^2 = 0.78, \quad DW = 1.62$$

$$C_2 = -4.3 + \underset{(2.85)}{0.0069}(HR) + \underset{(1.82)}{27184.51}(1/HR) - \underset{(6.07)}{0.000048}(HR)(CU)$$
$$-\underset{(1.80)}{526.53}(FO/CO) + \underset{(1.89)}{29315.99}(FO/CO)^2, \quad \bar{R}^2 = 0.91, \quad DW = 2.53$$

KORADI :

(JANUARY 1980 - MARCH 1981)

$$C_1 = 126.13 - \underset{(2.95)}{3.75}(CU) + \underset{(3.00)}{0.03}(CU)^2, \quad \bar{R}^2 = 0.89, \quad DW = 2.21$$

$$C_2 = 12.81 + \underset{(4.38)}{0.0032}(HR) + \underset{(1.62)}{2679.76}(1/HR) - \underset{(12.93)}{0.000043}(HR)(CU)$$
$$-\underset{(1.57)}{50.55}(LDO/CO) + \underset{(1.70)}{984.07}(LDO/CO)^2, \quad \bar{R}^2 = 0.94, \quad DW = 1.98$$

PARLI VAIJNATU :

(JANUARY 1980 - MARCH 1981)

$$C_1 = \underset{}{73.48} - \underset{(4.09)}{1.4(CU)} + \underset{(3.51)}{0.0074(CU)^2}, \quad \bar{R}^2 = 0.90, \quad DW = 1.21$$

$$C_2 = 149.21 - \underset{(1.55)}{0.088(HR)} + \underset{(1.51)}{0.000013(HR)^2} + \underset{(6.33)}{0.000039(HR)(CU)}$$

$$- \underset{(2.21)}{2163.07(LDO/CO)} + \underset{(2.23)}{662972.81(LDO/CO)^2}, \quad \bar{R}^2 = 0.88, \quad DW = 2.18$$

TROMBAY (TATA) :

(OCTOBER 1979 - MARCH 1981)

$$C_1 = 20.23 - \underset{(3.46)}{0.36(CU)} + \underset{(2.85)}{0.0022(CU)^2}, \quad \bar{R}^2 = 0.98, \quad DW = 1.31$$

$$C_2 = -4071.12 + \underset{(2.22)}{0.69(HR)} + \underset{(2.15)}{6048785.4(1/HR)} + \underset{(1.61)}{0.000074(HR)(CU)}$$

$$- \underset{(1.68)}{37.35(NG/OIL)} + \underset{(1.58)}{21.22(NG/OIL)^2}, \quad \bar{R}^2 = 0.91, \quad DW = 1.42$$

DHUVARAN :

(OCTOBER 1979 - MARCH 1981)

$$C_1 = 9.55 - \underset{(6.19)}{0.11(CU)} + \underset{(4.22)}{0.00057(CU)^2}, \quad \bar{R}^2 = 0.97, \quad DW = 1.51$$

$$C_2 = -158.44 + \underset{(2.02)}{0.032(HR)} + \underset{(1.93)}{231183.16(1/HR)} + \underset{(6.90)}{0.00001(HR)(CU)}$$

$$- \underset{(2.23)}{27.36(NG/RFO)} + \underset{(2.14)}{222.18(NG/RFO)^2} - \underset{(1.57)}{7.75(LDO/RFO)}$$

$$+ \underset{(1.55)}{113.85(LDO/RFO)^2}, \quad \bar{R}^2 = 0.96, \quad DW = 2.51.$$

UKAI :

(OCTOBER 1979 - JUNE 1981)

$$C_1 = 15.28 - \underset{(16.18)}{0.51}(CU) + \underset{(11.67)}{0.0054}(CU)^2, \quad \bar{R}^2 = 0.99, \quad DW = 1.61$$

$$\begin{aligned} C_2 = {} & -38.66 + \underset{(2.93)}{0.0089}(HR) + \underset{(2.47)}{64356.77}(1/HR) + \underset{(19.79)}{0.000042}(HR)(CU) \\ & - \underset{(5.64)}{268.78}(LDO/CO) + \underset{(7.03)}{15967.1}(LDO/CO)^2, \quad \bar{R}^2 = 0.98, \quad DW = 1.81 \end{aligned}$$

KOTHAGUDAM (A) :

(JANUARY 1980 - MARCH 1981)

$$C_1 = 48.35 - \underset{(6.21)}{1.1}(CU) + \underset{(4.51)}{0.0082}(CU)^2, \quad \bar{R}^2 = 0.98, \quad DW = 1.94$$

$$\begin{aligned} C_2 = {} & -4849.28 + \underset{(3.26)}{0.81}(HR) + \underset{(3.23)}{7363550.0}(1/HR) - \underset{(9.81)}{0.000075}(HR)(CU) \\ & - \underset{(1.76)}{299.3}(FO/CO) + \underset{(1.64)}{4266.3}(FO/CO)^2, \quad \bar{R}^2 = 0.98, \quad DW = 2.00 \end{aligned}$$

KOTHAGUDAM(B) :

(APRIL 1980 - MARCH 1981)

$$C_1 = 182.51 - \underset{(9.04)}{8.36}(CU) + \underset{(7.09)}{0.1}(CU)^2, \quad \bar{R}^2 = 0.89, \quad DW = 1.18$$

$$\begin{aligned} C_2 = {} & -680.52 + \underset{(2.04)}{0.13}(HR) + \underset{(2.02)}{1325708.0}(1/HR) - \underset{(2.46)}{0.00064}(HR)(CU) \\ & - \underset{(2.57)}{520.60}(FO/CO) + \underset{(2.51)}{1306.66}(FO/CO)^2, \quad \bar{R}^2 = 0.92, \quad DW = 2.17 \end{aligned}$$

KOTHAGUDAM(C):

(JANUARY 1980 - MARCH 1981)

$$C_1 = 180.8 - \underset{(9.33)}{8.78}(CU) + \underset{(7.33)}{0.11}(CU)^2, \quad \bar{R}^2 = 0.90, \quad DW = 1.16$$

$$\begin{aligned} C_2 = {} & -1129.73 + \underset{(2.04)}{0.23}(HR) + \underset{(2.09)}{1836392.45}(1/HR) - \underset{(2.44)}{0.00066}(HR)(CU) \\ & - \underset{(2.53)}{607.32}(FO/CO) + \underset{(2.46)}{1235.83}(FO/CO)^2, \quad \bar{R}^2 = 0.93, \quad DW = 1.16 \end{aligned}$$

RAMAGUNDAM (B) :

(JANUARY 1980 - MARCH 1981)

$$C_1 = 73.82 - \underset{(1.96)}{1.86}(CU) + \underset{(1.97)}{0.013}(CU)^2, \quad \bar{R}^2=0.99, \quad DW=2.06$$

$$C_2 = -69.79 + \underset{(1.82)}{0.018}(HR) + \underset{(1.73)}{116723.14}(1/HR) - \underset{(2.58)}{0.000025}(HR)(CU)$$

$$- \underset{(2.54)}{34.51}(FO/CO) + \underset{(2.04)}{1323.4}(FO/CO)^2, \quad \bar{R}^2=0.93, DW=2.24$$

NEYVELI LIGNITE CORPORATION :

(APRIL 1980 - DECEMBER 1981)

$$C_2 = 23.62 - \underset{(5.60)}{0.31}(CU) + \underset{(3.69)}{0.002}(CU)^2, \quad \bar{R}^2=0.96, \quad DW=1.96$$

$$C_2 = -7.83 + \underset{(2.27)}{0.0062}(HR) + \underset{(2.01)}{40085.5}(1/HR) - \underset{(12.77)}{0.000022}(HR)(CU)$$

$$- \underset{(2.18)}{6.28}(FO/LIG) + \underset{(2.20)}{12.97}(FO/LIG)^2, \quad \bar{R}^2 = 0.92, \quad DW = 2.04$$

ENNORE :

(OCTOBER 1979 - MARCH 1981)

$$C_1 = 55.23 - \underset{(11.01)}{1.66}(CU) + \underset{(6.98)}{0.013}(CU)^2, \quad \bar{R}^2=0.98, \quad DW=1.26$$

$$C_2 = -998.86 + \underset{(2.22)}{0.16}(HR) + \underset{(2.08)}{1546478.0}(1/HR) + \underset{(6.19)}{0.00013}(HR)(CU)$$

$$+ \underset{(2.20)}{62.02}(FO/CO) + \underset{(2.06)}{0.48}(1/(FO/CO)), \quad \bar{R}^2=0.84, \quad DW=1.86$$

BASIN BRIDGE :

(APRIL 1980 - MARCH 1981)

$$C_1 = 30.15 - \underset{(2.72)}{0.59}(CU) + \underset{(2.66)}{0.0044}(CU)^2, \quad \bar{R}^2=0.95, \quad DW=1.40$$

$$C_2 = -850.98 + \underset{(2.36)}{0.11}(HR) + \underset{(2.34)}{1808314.5}(1/HR) - \underset{(17.57)}{0.00012}(HR)(CU)$$

$$- \underset{(2.08)}{11.49}(FO/CO) + \underset{(2.19)}{61.54}(FO/CO)^2, \quad \bar{R}^2=0.95, \quad DW=1.47$$

PANKI :

(JANUARY 1980 - JUNE 1981)

$$C_1 = 45.63-\underset{(12.24)}{0.98}(CU)+\underset{(8.20)}{0.0066}(CU)^2, \quad \bar{R}^2=0.98, \quad DW=1.14$$

$$C_2 = -125.13+\underset{(2.53)}{0.021}(HR)+\underset{(1.67)}{202743.19}(1/HR)+\underset{(5.06)}{0.00011}(HR)(CU)$$

$$-\underset{(2.41)}{223.43}(LDO/CO)+\underset{(2.73)}{2560.58}(LDO/CO)^2, \quad \bar{R}^2=0.93, \quad DW=2.34$$

HARDUAGANJ (B) :

(APRIL 1980 - MARCH 1981)

$$C_1=46.99-\underset{(3.19)}{1.35}(CU)+\underset{(3.09)}{0.01}(CU)^2, \quad \bar{R}^2=0.97, \quad DW = 1.61$$

$$C_2= -5223.12+\underset{(2.52)}{0.92}(HR)+\underset{(2.53)}{8930776.4}(1/HR)-\underset{(2.20)}{0.0029}(HR)(CU)$$

$$-\underset{(2.81)}{522.91}(FO/CO)+\underset{(2.71)}{4469.22}(FO/CO)^2, \quad \bar{R}^2=0.91, \quad DW = 2.14$$

HARDUAGANJ (C) :

(APRIL 1980 - MARCH 1981)

$$C_1 = 109.08-\underset{(2.28)}{3.8}(CU)+\underset{(2.23)}{0.029}(CU)^2, \quad \bar{R}^2=0.88, \quad DW=1.01$$

$$C_2 =-137.66+\underset{(2.63)}{0.029}(HR)+\underset{(2.75)}{246248.31}(1/HR)-\underset{(2.46)}{0.000099}(HR)(CU)$$

$$-\underset{(2.17)}{34.13}(FO/CO)+\underset{(1.75)}{144.47}(FO/CO)^2, \quad \bar{R}^2=0.84, \quad DW=2.08$$

BARAUNI :

(JANUARY 1980 - MARCH 1981)

$$C_1 = 111.58-\underset{(11.92)}{6.18}(CU)+\underset{(8.41)}{0.086}(CU)^2, \quad \bar{R}^2=0.98, \quad DW = 1.27$$

$$C_2 = -473.61+\underset{(3.62)}{0.045}(HR)+ \underset{(2.80)}{723871.52}(1/HR)+\underset{(3.93)}{0.00035}(HR)(CU)$$

$$+\underset{(3.31)}{382.92}(FO/CO)+\underset{(1.66)}{5.58}(1/(FO/CO)), \quad \bar{R}^2=0.92, \quad DW=2.35$$

DURGAPUR POWER PROJECTS LTD :

(APRIL 1980 - MARCH 1981)

$$C_1 = 24.57 - \underset{(2.20)}{0.91}(CU) + \underset{(1.63)}{0.011}(CU)^2, \quad \bar{R}^2 = 0.84, \quad DW = 0.78$$

$$C_2 = -869.54 + \underset{(2.58)}{0.15}(HR) + \underset{(2.57)}{1359445.3}(1/HR) - \underset{(10.88)}{0.000061}(HR)(CU)$$

$$- \underset{(1.85)}{28.73}(FO/CO) + \underset{(1.89)}{58.11}(FO/CO)^2, \quad \bar{R}^2 = 0.91, \quad DW = 1.39$$

fixed in nature irrespective of the level of energy generation for the power plant concerned.

The estimated C_1 equations of all power plants in our sample contain CU and CU^2 as the independent terms. The bracketed terms below each coefficient represent the corresponding t-values for the respective coefficients. The values of $\bar{R}^2$ and DW statistics have also been reported. In all the cases, the t-values, $\bar{R}^2$ and the DW statistics are significant. Thus, it can be argued that at the individual plant level, the managers choose capacity utilization rate <u>ex ante</u> with respect to capital cost considerations alone.

In the next step, optimality calculations of CU have been undertaken. The cost minimizing solutions (i.e., those for which both the first-order and the second-order conditions are satisfied) of CU are exhibited in Table 7.2. For purposes of comparison, the observed CU and IC of the individual power plants are also tabulated. The optimal CU's vary widely from the observed magnitudes. They also vary with respect to the installed capacity of the power plant concerned. For small power plants, e.g., Bhusawal (I) (IC = 62.50 MW), Paras (IC = 92.50 MW), Parli Vaijnatu (IC = 60.00 MW), and Ramagundam (B) (IC= 62.50 MW), the respective optimal CU's are close to their observed counterparts. The only exception is the Basin Bridge (IC=90 MW) plant which is quite old and is subject to operational hazards

TABLE 7.2

DETERMINISTIC MODEL : OPTIMAL CALCULATIONS OF CU

Sl. No.	Name of the Power Plant	IC (MW)	CU (observed) (percentage)	CU (optimal) (percentage)
1.	Gurumanakdeb (Bhatinda)	440.00	36.27	54.88
2.	Faridabad	120.00	33.62	43.06
3.	Panipat	220.00	34.06	51.86
4.	Indraprastha	284.10	63.81	86.57
5.	Badarpur	510.00	49.96	66.96
6.	Nasik	280.00	63.84	81.67
7.	Bhusawal(I)	62.50	73.00	79.89
8.	Bhusawal (II)	210.00	43.16	58.69
9.	Paras	92.50	64.85	72.55
10.	Koradi	680.00	59.11	61.53
11.	Parli Vaijnatu	60.00	85.83	94.34
12.	Trombay (Tata)	337.50	68.49	80.46
13.	Dhuvaran	534.00	69.64	99.54

contd ...

TABLE 7.2 (contd...)

Sl. No.	Name of the Power Plant	IC (MW)	CU (observed) (percentage)	CU (optimal) (percentage)
14.	Ukai	640.00	37.50	47.03
15.	Kothagudam(A)	240.00	50.21	67.27
16.	Kothagudam(B)	220.00	21.52	41.37
17.	Kothagudam(C)	220.00	32.29	41.33
18.	Ramagund m(B)	62.50	68.56	72.14
19.	Neyveli Lignite Corp.	600.00	61.01	77.30
20.	Ennore	450.00	36.79	61.80
21.	Basin Bridge	90.00	41.70	66.40
22.	Panki	284.00	51.05	74.38
23.	Harduaganj(B)	210.00	34.38	50.41
24.	Harduaganj(C)	170.00	36.41	65.30
25.	Barauni	145.00	25.79	36.09
26.	Durgapur Power Projects	285.00	28.54	40.40

as reported in Chapter 5. Among the large power plants, Koradi (IC= 680 MW) has set an optimal CU which is quite comparable to the prevailing utilization rate during the sample period. It may be noted that the optimal CU, calculated from monthly time series of individual power stations, exhibits more realistic values as compared to those computed in cross-section in Chapter 6.

7.3 FUEL COST EQUATION

Recall from Chapter 6 that, at the cross-section level, factor proportions (i.e., FO/CO, LDO/CO) do vary with respect to installed capacity (MW) and gross average energy generation (MkWh) across firms in our sample during the period under consideration. It is expected that the same will hold good for the individual power stations with respect to gross average energy generation. This can be shown for Koradi and Faridabad power stations by referring to Tables 7.3 and 7.4 respectively. The corresponding graphs, namely, Figures 7.1 and 7.2, show the general non-linear relationship (predominantly downward slope) between average energy generation and FO/CO. Hence, it appears that at the plant level the expansion path is non-linear. Given the factor prices along an iso-cost curve the changing factor proportions will give rise to substitution possibilities among fuels due to technological constraints.

TABLE 7. 3

KORADI THERMAL POWER STATION
(JANUARY 1980 - MARCH 1981)

Energy Generation (MkWh)	FO/CO	LDO/CO	CO (Kcal/kWh)
325.30	0.027	0.0053	2673.53
272.73	0.018	0.0088	2923.85
286.27	0.021	0.0084	2595.67
300.47	0.026	0.0140	2875.94
298.65	0.024	0.0320	2763.64
282.97	0.048	0.0350	2861.66
267.20	0.00068	0.000016	2002.66
263.76	0.00054	0.0000017	1735.71
263.83	0.00097	0.000056	1735.41
263.79	0.000046	0.000032	1520.95
351.39	0.00038	0.000025	1497.37
390.97	0.00016	0.0000018	1599.68
333.30	0.011	0.0021	1799.22
258.65	0.049	0.000021	1899.98
239.66	0.05	0.0015	1802.37

TABLE 7.4

FARIDABAD THERMAL POWER STATION
(JANUARY 1980 - JUNE 1981)

Energy Generation (MkWh)	FO/CO	LDO/CO	CO (Kcal/kWh)
14.35	0.089	0.052	3959.98
21.96	0.115	0.01	3840.86
50.49	0.041	0.0041	4043.22
34.70	0.049	0.012	3890.60
6.02	0.057	0.02	2327.51
3.43	0.063	0.039	5839.42
25.12	0.06	0.014	4179.27
25.80	0.053	0.018	3760.27
40.09	0.033	0.0068	3143.16
33.23	0.026	0.0079	3310.36
33.01	0.045	0.01	3362.92
35.27	0.077	0.011	2240.05
25.21	0.12	0.036	2437.91
23.44	0.044	0.015	3095.00
25.56	0.038	0.024	2836.18
46.46	0.043	0.013	3141.41
47.59	0.059	0.0045	3084.96
38.09	0.073	0.016	3350.92

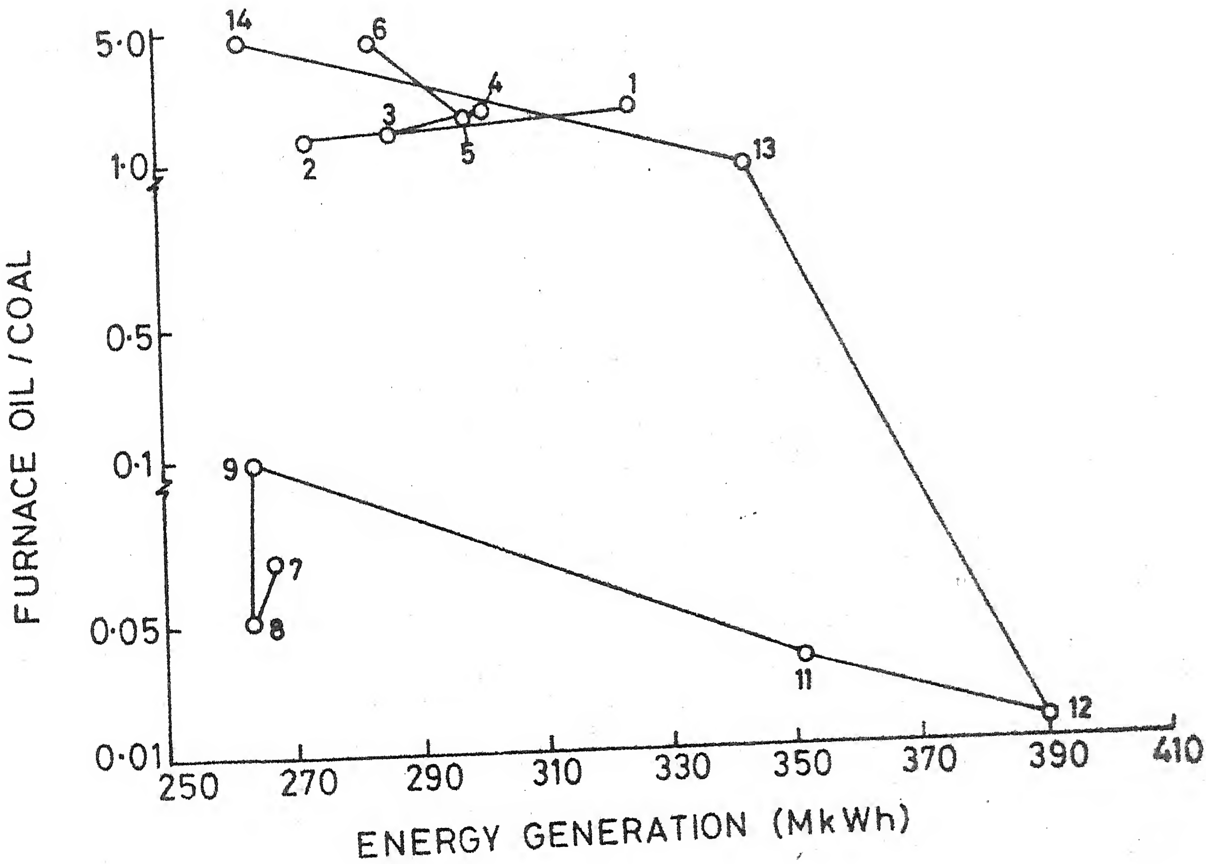

FIG.7·1 KORADI: ENERGY GENERATION VS FURNACE OIL/COAL (FO /CO)

Note: The serial nos. correspond to different months of observation as detailed in Table 7·3

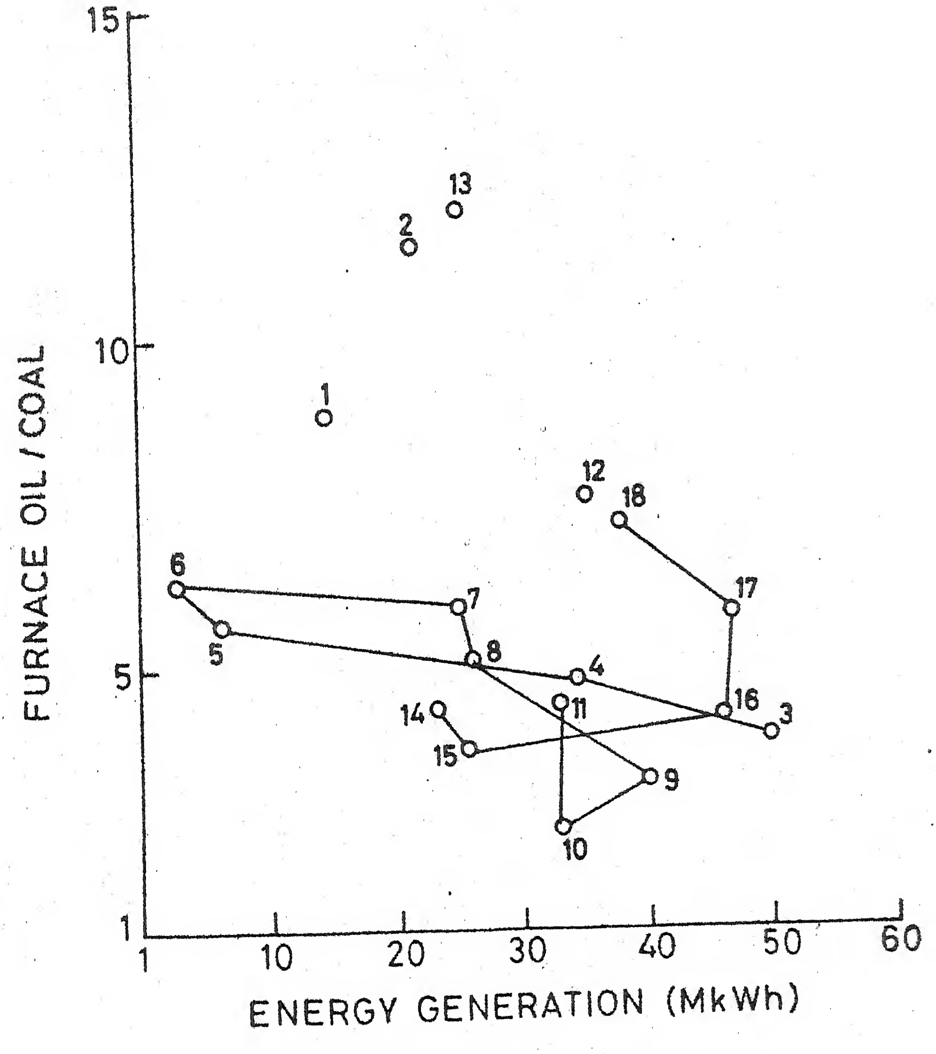

FIG. 7·2 FARIDABAD: ENERGY GENERATION VS FURNACE OIL / COAL (FO / CO)

Note: The serial nos. correspond to different months of observation as detailed in Table 7·4

We estimated the equations for the fuel cost per kWh which varies non-linearly with HR (the index of output) and factor proportions in physical terms. Dimension and aggregation problems are taken care of in the formulation. All fuels are measured in Kilocalories per kWh to produce a given level of output.

In the deterministic specifications, the estimated best fit C_2 (fuel cost per kWh), equations are summarized along with C_1 equations in Table 7.1 for all the plants in the sample. The fuel cost per kWh has been deflated by appropriate fuel price indices as mentioned in Chapter 5. The C_2 equations contain HR, (1/HR , or HR^2), an interactive term (HR)(CU), (FO/CO), $(FO/CO)^2$, or 1/(FO/CO)), (LDO/CO), ($(LDO/CO)^2$, or 1/(LDO/CO)), (CO/RFO), $(CO/RFO)^2$, (FO/RFO), $(FO/RFO)^2$, (LDO/RFO), $(LDO/RFO)^2$, (NG/OIL), $(NG/OIL)^2$ and similar ratios of minor to major fuel, as relevant for a particular technology, as independent variables. The numbers in the brackets are the t-values of the respective coefficients. The values of $\bar{R}^2$, the DW statistic and the 't' are quite significant. In general, the interactive term (HR)(CU) is negative as expected (i.e., as CU increases along with HR, fuel cost per kWh decreases). But this term is observed to be positive for Nasik, Bhusawal (I), Parli Vaijnatu, Trombay (Tata), Dhuvaran, Ukai, Ennore, Panki and Barauni. It simply implies that the optimal HR is

close to *ex ante* HR where the options to decrease fuel cost per kWh are limited. The plant manager is unable to enhance the fuel efficiency of the capital equipment as CU increases beyond a certain point.

In the next stage, the optimum values of HR and fuel ratios were computed from the first-order conditions after ensuring that the second-order conditions for cost minimization were fulfilled. The optimal values, vis-a-vis the observed magnitudes, of HR and fuel combinations are reported in Tables 7.5 and 7.6 respectively. Tables 7.7(a) and 7.7(b) represent optimal values of fuel quantities in comparison to observed counterparts for coal-fired and oil and lignite fired power plants respectively. Among the small plants Parli Vaijnatu (IC = 60 MW) and Ramagundam (B) (IC = 62.5 MW) have observed values of HR which are quite close to the optimal magnitudes. In the case of large plants Gurunanakdeb (Bhatinda) (IC = 440 MW), Indraprastha (IC = 284.1 MW), Trombay (Tata) (IC = 337.5 MW), and Dhuvaran (IC = 534 MW) have experienced HR's which are quite comparable to optimal configurations.

Comparing fuel ratios (i.e., fuel-mix) across firms from monthly time series analysis, it may be observed that significant *ex post* fuel substitution possibilities do exist during the period under consideration. Furnace oil may be substituted for coal in the case of Gurunanakdeb (Bhatinda)

TABLE 7.5

DETERMINISTIC MODEL : OPTIMAL CALCULATIONS OF HR

Sl. No.	Name of the Power Plant	IC (MW)	HR (observed) (Kcal/kWh)	HR (optimal) (KCal/kWh)
1.	Gurunanakdeb (Bhatinda)	440.00	3081.88	2963.61
2.	Faridabad	120.00	3704.14	3031.24
3.	Panipat	220.00	4066.57	3616.10
4.	Indraprastha	284.10	3461.48	3424.91
5.	Badarpur	510.00	3417.32	3306.79
6.	Nasik	280.00	2531.32	2321.91
7.	Bhusawal(I)	62.50	3321.00	3241.52
8.	Bhusawal(II)	210.00	3229.20	2765.39
9.	Paras	92.50	3300.72	2822.31
10.	Koradi	680.00	2217.92	2198.75
11.	Parli Vaijnatu	60.00	3286.31	3206.34
12.	Trombay(Tata)	337.50	2978.67	2939.99
13.	Dhuvaran	534.00	2785.52	2646.88

contd ...

TABLE 7.5 (contd ...)

Sl. No.	Name of the Power Plant	IC (MW)	HR (observed) KCal/kWh	HR (optimal) KCal/kWh
14.	Ukai	640.00	3048.34	2429.32
15.	Kothagudam(A)	240.00	3114.92	3020.17
16.	Kothagudam(B)	220.00	3703.09	3511.09
17.	Kothagudam(C)	220.00	3301.63	3005.95
18.	Ramagundam(B)	62.50	2787.35	2682.64
19.	Neyveli Lignite Corp.	600.00	3405.18	2988.80
20.	Ennore	450.00	3236.94	3049.42
21.	Basin Bridge	90.00	4820.22	4282.24
22.	Panki	284.00	3629.40	2625.01
23.	Harduaganj(B)	210.00	3772.90	3400.98
24.	Harduaganj(C)	170.00	3456.51	3296.88
25.	Barauni	145.00	4262.99	3545.24
26.	Durgapur Power Projects Ltd.	285.00	3239.47	3060.67

TABLE 7.6

DETERMINISTIC MODEL : FUEL-MIX COMPARISONS

Sr. No.	Name of the Power Plant	FO/CO observed	FO/CO optimal	LDO/CO observed	LDO/CO optimal	NG/OIL observed	NG/OIL optimal	NG/RFO observed	NG/RFO optimal	LDO/RFO observed	LDO/RFO optimal	FO/LIG observed	FO/LIG optimal
1	2	3	4	5	6	7	8	9	10	11	12	13	14
1.	Gurunanakdeb	0.058	0.12	0.011	0.011	-	-	-	-	-	-	-	-
2.	Faridabad	0.06	0.06	0.018	0.019	-	-	-	-	-	-	-	-
3.	Panipat	0.27	0.37	0.048	0.048	-	-	-	-	-	-	-	-
4.	Indraprastha	0.059	0.11	-	-	-	-	-	-	-	-	-	-
5.	Badarpur	0.078	0.15	0.0018	0.0018	-	-	-	-	-	-	-	-
6.	Nasik	0.019	0.019	0.01	0.0075	-	-	-	-	-	-	-	-
7.	Bhusawal (I)	0.02	0.033	0.0007	0.0007	-	-	-	-	-	-	-	-
8.	Bhusawal (II)	0.11	0.29	0.011	0.011	-	-	-	-	-	-	-	-
9.	Paras	0.0064	0.009	0.00043	0.00043	-	-	-	-	-	-	-	-
10.	Koradi	0.021	0.021	0.0092	0.026	-	-	-	-	-	-	-	-

contd ...

1	2	3	4		6	7	8	9	10	11	12	13	1
11.	Parli Vaijnatu	0.0038	0.0038	0.0013	0.0016	-							
12.	Trombay(Tata)	-	-	-	-	0.38	0.88						
13.	Dhuvaran	-	-	-	-	-	-	0.059	0.062	0.016	0.034	-	
14.	Ukai	0.18	0.18	0.0069	0.0084	-	-	-	-	-	-	-	
15.	Kothagudam(A)	0.017	0.035	-	-	-	-	-	-	-	-	-	
16.	Kothagudam(B)	0.10	0.20	-	-	-	-	-	-	-	-	-	
17.	Kothagudam(C)	0.12	0.25	-	-	-	-	-	-	-	-	-	
18.	Ramagundam(B)	0.0081	0.013	0.0017	0.0017	-	-	-	-	-	-	-	
19.	Neyveli Lignite Corp.	-	-	-	-	-	-	-	-	-	-	0.110.	
20.	Ennore	0.091	0.088	0.0066	0.0066	-	-	-	-	-	-	-	

contd ...

1.	2.	3.	4.	5.	6.	7.	8.	9.	10.	11.	12.	13.	14
21.	Basin Bridge	0.23	0.093	-	-	-	-	-	-	-	-	-	-
22.	Panki	0.011	0.011	0.032	0.044	-	-	-	-	-	-	-	-
23.	Harduaganj(B)	0.14	0.058	-	-	-	-	-	-	-	-	-	-
24.	Harduaganj(C)	0.052	0.12	-	-	-	-	-	-	-	-	-	-
25.	Barauni	0.16	0.12	0.012	0.012	-	-	-	-	-	-	-	-
26.	Durgapur Power Projects Ltd.	0.10	0.25	-	-	-	-	-	-	-	-	-	-

TABLE 7.7(a)

DETERMINISTIC MODEL : OPTIMAL FUEL QUANTITIES (COAL-FIRED POWER PLANTS)

Sl. No.	Name of the Power Plants	CO (observed)	CO (optimal)	FO (observed)	FO (optimal)	LDO (observed)	LDO (optimal)
1	2	3	4	5	6	7	8
1.	Gurunanakdeb (Bhatinda)	2882.08	2626.87	167.55	307.35	32.24	29.39
2.	Faridabad	3435.78	2810.35	206.06	168.55	62.30	52.34
3.	Panipat	3072.02	2554.07	845.82	938.38	148.73	123.65
4.	Indraprastha	3267.53	3079.00	193.94	345.91	-	-
5.	Badarpur	3163.42	2875.06	248.14	426.50	5.76	5.23
6.	Nasik	2458.43	2261.39	47.24	43.46	25.64	17.06
7.	Bhusawal(I)	3253.33	3135.62	65.30	103.61	2.37	2.29
8.	Bhusawal(II)	2873.73	2122.46	322.77	618.78	32.70	31.46
9.	Paras	3278.27	2796.00	21.04	25.11	1.42	1.21
10.	Koradi	2152.51	2100.05	44.37	44.10	19.86	54.60
11.	Parli Vaijnatu	3189.91	3188.86	12.28	12.28	4.20	5.20

contd ...

1	2	3	4	5	6	7	8
12.	Ukai	2563.17	2040.11	467.42	372.03	17.75	17.17
13.	Kothagudam(A)	3063.12	2917.82	51.80	102.35	-	-
14.	Kothagudam(B)	3364.04	2927.83	339.04	583.26	-	-
15.	Kothagudam(C)	2936.06	2413.04	365.57	592.91	-	-
16.	Ramagundam(B)	2760.12	2643.58	22.45	34.47	4.78	4.58
17.	Ennore	2948.79	2785.08	268.66	245.93	19.49	18.41
18.	Basin Bridge	3918.43	3916.74	901.78	365.50	-	-
19.	Panki	3501.57	2490.07	36.98	26.29	113.07	108.64
20.	Harduaganj(B)	3317.90	3213.02	455.00	187.96	-	-
21.	Harduaganj(C)	3286.23	2948.63	170.28	348.25	-	-
22.	Barauni	3634.59	3128.66	583.24	377.70	45.16	38.87
23.	Durgapur Power Projects	2945.78	2453.93	293.69	606.74	-	-

NOTE : All figures are expressed in KCal/kWh.

TABLE 7.7(b)

DETERMINISTIC MODEL: OPTIMAL FUEL QUANTITIES
(OIL AND LIGNITE FIRED POWER PLANTS)

Fuel Quantities	Trombay (Tata)	Dhuvaran	Neyveli Lignite Corporation
Natural Gas (NG) (observed)	806.11	117.61	-
Natural Gas (NG) (optimal)	1376.84	114.69	-
Residual Fuel Oil (RFO) (observed)	2131.64	1986.08	-
Residual Fuel Oil(RFO) (optimal)	1563.15	1862.81	-
Lignite (LIG) (observed)	-	42.50	3061.09
Lignite (LIG) (optimal)	-	39.86	2395.35
Coal (CO) (observed)	-	225.92	-
Coal (CO) (optimal)	-	211.90	-
Furnace Oil (FO) (observed)	-	377.66	326.89
Furnace Oil (FO) (optimal)	-	354.21	579.99
Light Diesel Oil(LDO) (observed)	-	31.57	17.19
Light Diesel Oil(LDO) (optimal)	-	63.42	13.46

NOTE : All figures are expressed in Kcal/kWh.

(IC = 440 MW), Indraprastha (IC = 284.1 MW), Badarpur (IC = 510 MW), Bhusawal (II) (IC = 210 MW), Kothagudam (A) (IC = 240 MW), Kothagudam (B) (IC = 220 MW), Kothagudam (C) (IC = 220 MW), Ramagundam (B) (IC = 62.5 MW), Harduaganj (C) (IC = 170 MW), and Durgapur Power Projects (IC = 285 MW). In an oil-fired power plant like Trombay (Tata) (IC = 337.5MW), a significant amount of natural gas can be substituted for oil (LSHS or RFO). Similarly, substitution of furnace oil for lignite is indicated in the Neyveli Lignite Corporation (IC = 600 MW) in Tamil Nadu. The hypothesis of *ex post* fuel substitution is further substantiated by Table 7.7(a) and 7.7(b), where optimal fuel quantities are exhibited in comparison to the observed averages.

It may, therefore, be observed that whereas the cross-section analysis across plants demonstrated the existence of fuel substitution *ex ante* in the peak demand quarter over similar technological characteristics, the present chapter has been able to establish the possibility of *ex post* fuel substitution in the individual power plants with different technological background. But the existence of *ex post* fuel substitution exhibited in the present chapter is relatively new and is subject to one major qualification. It is well-known from engineering principles that the process of steam electric power generation has an in-built stochastic nature. We ought to study the extent of fuel

substitution among different power plants in the context of random behaviour of plant load factor and unforeseen forced outages. This will be attempted in monthly time series analysis of a stochastic model in Chapter 8. The combined results of Sections 2 and 3 are summarized in a nutshell in Table 7.8.

7.4 MEASURES OF INEFFICIENCY

As proposed in Chapter 6, the fuel cost component of the planning inefficiency can be computed in the following manner. In step 1, we compute the optimal CU from the capital cost (CC/kWh) equation. For this value of CU we compute the optimal fuel consumption (Kcal/kWh) from the fuel cost (FC/kWh) equation. This gives us the optimal values of HR and the fuel consumption. In step 2, we replace the optimal CU with the observed CU and repeat the procedure. The difference in the HR and fuel-mix so computed provides the desired measure of inefficiency.

Tables 7.9, and 7.10(a) -7.10(b) are constructed with a view to illustrate the extent of planning and operational inefficiencies prevailing in the decision making process of the individual power plants. In general, the operational inefficiency is larger than the fuel cost component of planning inefficiency. However, due to the relative flatness of the fuel cost curves we are unable to sharply identify the extent of planning inefficiency in some plants, e.g.,

TABLE 7.8

DETERMINISTIC MODEL : SUMMARY OF RESULTS

Sl. No.	Name of the Power Plant	IC (MW)	CU (observed) (%)	CU (optimal) (%)	HR (ex ante) (Kcal/kWh)	HR (ex post) (Kcal/kWh)	HR optimal at CU optimal	HR optimal at CU observed
1	2	3	4	5	6	7	8	9
1.	Gurunanakdeb (Bhatinda)	440.00	36.27	54.88	2365.00	3081.88	2963.61	2764.20
2.	Faridabad	120.00	33.62	43.06	2500.00	3704.14	3031.24	2977.70
3.	Panipat	220.00	34.06	51.86	2600.00	4066.57	3616.10	3418.07
4.	Indraprastha	284.10	63.81	86.57	2324.00	3461.48	3424.91	3242.04
5.	Badarpur	510.00	49.96	66.96	2520.00	3417.32	3306.79	3038.87
6.	Nasik	280.00	63.84	81.67	2305.00	2531.32	2321.91	2323.42
7.	Bhusawal(I)	62.50	73.00	79.89	2500.00	3321.00	3241.52	3242.87
8.	Bhusawal(II)	210.00	43.16	58.69	2365.00	3229.20	2765.39	2730.33
9.	Paras	92.50	64.85	72.55	2600.00	3300.72	2822.31	2679.78
10.	Koradi	680.00	59.11	61.53	2069.00	2217.92	2193.75	2017.60
11.	Parli Vaijnatu	60.00	85.83	94.34	2500.00	3286.31	3206.34	3218.91

contd ...

1	2	3	4	5	6	7	8	9
12.	Trombay (Tata)	337.50	68.49	80.46	2500.00	2978.67	2939.99	2941.86
13.	Dhuvaran	534.00	69.64	99.54	2365.00	2785.52	2646.88	2659.32
14.	Ukai	640.00	37.50	47.03	2365.00	3048.34	2429.32	2475.17
15.	Kothagudam(A)	240.00	50.21	67.27	2500.00	3114.92	3020.17	3017.77
16.	Kothagudam(B)	220.00	21.52	41.37	2500.00	3703.09	3511.09	3319.08
17.	Kothagudam(C)	220.00	32.29	41.33	2500.00	3301.63	3005.95	2962.54
18.	Ramagundam(B)	62.50	68.56	72.14	2365.00	2787.35	2682.64	2675.25
19.	Neyveli Lignite Corp.	600.00	61.01	77.30	2365.00	3405.18	2988.80	2877.16
20.	Ennore	450.00	36.79	61.80	2500.00	3236.94	3049.42	3078.74
21.	Basin Bridge	90.00	41.70	66.40	2600.00	4820.22	4282.24	4218.49
22.	Panki	284.00	51.05	74.38	2324.00	3629.40	2625.01	2747.92
23.	Harduaganj(B)	210.00	34.38	50.41	2500.00	3772.90	3400.98	3302.32
24.	Harduaganj(C)	170.00	36.41	65.30	2500.00	3456.51	3296.88	3106.47
25.	Barauni	145.00	25.79	36.09	2500.00	4262.99	3545.24	3660.07
26.	Durgapur Power Projects	285.00	28.54	40.40	2365.00	3239.47	3060.67	3053.09

TABLE 7.9

DETERMINISTIC MODEL : EXTENT OF INEFFICIENCY IN CHOOSING HR

Sl. No.	Name of the Power Plant	HR (observed)	HR (optimal at CU optimal)	HR (optimal at CU observed)
1.	Gurunanakdeb (Bhatinda)	3081.88	2963.61	2764.20
2.	Faridabad	3704.14	3031.24	2977.70
3.	Panipat	4066.57	3616.10	3418.07
4.	Indraprastha	3461.48	3424.91	3242.04
5.	Badarpur	3417.32	3306.79	3038.87
6.	Nasik	2531.32	2321.91	2323.42
7.	Bhusawal(I)	3321.00	3241.52	3242.87
8.	Bhusawal(II)	3229.20	2765.39	2730.33
9.	Paras	3300.72	2822.31	2679.78
10.	Koradi	2217.92	2198.75	2017.60
11.	Parli Vaijnatu	3286.31	3206.34	3218.91
12.	Trombay (Tata)	2978.67	2939.99	2941.86
13.	Dhuvaran	2785.52	2646.88	2659.32

contd ...

TABLE 7.9 (contd ...)

Sl. No.	Name of the Power Plant	HR (observed)	HR (optimal at CU optimal)	HR (optimal at CU observed)
14.	Ukai	3048.34	2429.32	2475.17
15.	Kothagudam(A)	3114.92	3020.17	3017.77
16.	Kothagudam(B)	3703.09	3511.09	3319.08
17.	Kothagudam(C)	3301.63	3005.95	2962.54
18.	Ramagundam(B)	2787.35	2682.64	2675.25
19.	Neyveli Lignite Corp.	3405.18	2988.80	2877.16
20.	Ennore	3236.94	3049.42	3078.74
21.	Basin Bridge	4820.22	4282.24	4218.49
22.	Panki	3629.40	2625.01	2747.92
23.	Harduaganj(B)	3772.90	3400.98	3302.32
24.	Harduaganj(C)	3456.51	3296.88	3106.47
25.	Barauni	4262.99	3545.24	3660.07
26.	Durgapur Power Projects Ltd.	3239.47	3060.67	3053.09

NOTE : All figures are expressed in Kcal/kWh.

TABLE 7.10 (a)

DETERMINISTIC MODEL: EXTENT OF INEFFICIENCY IN CHOOSING FUEL QUANTITIES (COAL-FIRED POWER PLANTS)

Sl. No.	Name of the Power Plant	CO(optimal at CU optimal)	CO(optimal at CU observed)	FO(optimal at CU optimal)	FO(optimal at CU observed)	LDO(optimal at CU optimal)	LDO(optimal at CU observed)
1	2	3	4	5	6	7	8
1.	Gurunanakdeb (Bhatinda)	2626.87	2450.12	307.35	286.67	29.39	27.41
2.	Faridabad	2810.35	2760.71	168.55	165.57	52.34	51.41
3.	Panipat	2554.07	2414.20	938.38	886.99	123.65	116.88
4.	Indraprastha	3079.00	2914.60	345.91	327.44	-	-
5.	Badarpur	2875.06	2642.12	426.50	391.94	5.23	4.81
6.	Nasik	2261.39	2262.87	43.46	43.49	17.06	17.07
7.	Bhusawal(I)	3135.62	3136.93	103.66	103.66	2.29	2.29
8.	Bhusawal(II)	2122.46	2095.55	618.78	610.94	31.46	23.84
9.	Paras	2796.00	2654.79	25.11	23.84	1.21	1.15
10.	Koradi	2100.05	1927.03	44.10	40.47	54.60	50.10
11.	Parli Vaijnatu	3188.86	3201.35	12.28	12.33	5.20	5.25

contd ...

TABLE 7.10a (contd...)

1	2	3	4	5	6	7	8
12.	Ukai	2040.11	2078.62	372.03	379.06	17.17	17.49
13.	Kothagudam(A)	2917.82	2915.50	102.35	102.27	-	-
14.	Kothagudam(B)	2927.83	2767.72	583.26	551.36	-	-
15.	Kothagudam(C)	2413.04	2378.19	592.91	584.35	-	-
16.	Ramagundam(B)	2643.58	2636.30	34.47	34.38	4.58	4.57
17.	Ennore	2785.08	2811.85	245.93	248.30	18.41	18.59
18.	Basin Bridge	3916.74	3858.43	365.50	360.06	-	-
19.	Panki	2490.07	2606.67	26.29	27.53	108.64	113.73
20.	Harduaganj(B)	3213.02	3119.81	187.96	182.51	-	-
21.	Harduaganj(C)	2948.63	2778.33	348.25	328.14	-	-
22.	Barauni	3128.66	3230.00	377.70	389.94	38.87	40.13
23.	Durgapur Power Projects	2453.93	2447.85	606.74	605.24	-	-

NOTE : All figures are in KCal/kWh.

TABLE 7.10(b)

DETERMINISTIC MODEL: EXTENT OF INEFFICIENCY IN CHOOSING FUEL QUANTITIES (OIL AND LIGNITE FIRED POWER PLANTS)

Fuel Quantities	Trombay (Tata)	Dhuvaran	Neyveli Lignite Corporation
Natural Gas (NG) (at CU optimal)	1376.84	114.69	-
Natural Gas (NG) (at CU observed)	1377.71	115.22	-
Residual Fuel Oil(RFO) (at CU optimal)	1563.15	1862.81	-
Residual Fuel Oil(RFO) (at CU observed)	1564.15	1871.56	-
Lignite (LIG) (at CU optimal)	-	39.86	2395.35
Lignite (LIG) (at CU observed)	-	40.05	2305.88
Coal (CO) (at CU optimal)	-	211.90	-
Coal (CO) (at CU observed)	-	212.89	-
Furnace Oil (FO) (at CU optimal)	-	354.21	579.99
Furnace Oil (FO) (at CU observed)	-	355.88	558.32
Light Diesel Oil(LDO) (at CU optimal)	-	63.42	13.46
Light Diesel Oil(LDO) (at CU observed)	-	63.72	12.95

NOTE : All figures are expressed in Kcal/kWh.

Nasik (IC = 280 MW), Bhusawal (I) (IC = 62.5 MW), Trombay (Tata) (IC = 337.5 MW), Dhuvaran (IC = 534 MW), Ramagundam (B) (IC = 62.5 MW), and Durgapur Power Projects Ltd (IC = 285 MW). Since the observed values of fuel quantities have already been reported in Tables 7.7a and 7.7(b), they are not duplicated in Tables 7.10(a) and 7.10(b).

Referring back to Table 7.2 we notice that in the time series analysis the planning inefficiency at the system level is captured by the discrepancy between the optimal CU and the observed magnitudes in percentages. Though the relative flatness of cost curve has underestimated the importance of planning inefficiencies carried over at the operation stage, we observe substantial amount of planning inefficiency as computed from capital cost/kWh equation. This is pronounced among relatively old power plants (small or large, i.e., irrespective of size). Once again, our statement is to be qualified in view of the presence of demand and production uncertainties, manifest in the production process itself. Hence, we need to explore the measures of inefficiency in physical as well as cost terms in the unfolding of stochastic variant of our model. Moreover, the prevalent non-identical units, manufactured by different companies and embodying different technological specifications, may themselves contribute to the existing large-scale system-wide inefficiencies.

In the absence of unit wise information of individual power plants,we have been unable to clearly estimate the subtle distinctions among various measures of inefficiencies. This result may be primarily due to the nature of the deterministic specification in what is essentially a stochastic environment.

7.5 COST IMPLICATIONS

It may be recalled from Chapter 6, Section 4 that at the system level, the installed capacity appears to be well-chosen. It follows therefore that system inefficiency as reflected in the capital cost/kWh would be small in magnitude. This can be demonstrated in the simplest case, e.g., the cross-section deterministic model, by substituting the optimal values of IC and CU in the capital cost equation and comparing the minimum capital cost with that computed with respect to the actual IC and the corresponding optimal CU.

However, this procedure cannot be repeated for all power plants because in the cross-section series of peak load quarter we have not considered plants where (i) periods of study do not match uniformly, and (ii) technology is widely different from the coal-fired one. An attempt will be made to perform these inefficiency calculations for a few selected power plants, e.g., Paras, Parli Vaijnatu, Kothagudam (A), Ramagundam (B), Panipat, Durgapur Power Projects and Indraprastha.

In the time series analysis, attempts have been made to compute capital cost as well as fuel cost components of planning inefficiency, and operational inefficiency.

The Methodology adopted for computation of inefficiencies is as follows :

(i) Capital cost component of planning inefficiency :
It is the deviation between (a) CC_1, capital cost resulting from the actual CU and (b) CC_2, capital cost corresponding to the optimal CU. This is done for the deterministic model.
(ii) Fuel cost component of planning inefficiency :
It is the discrepancy between (a) FC_1, fuel cost with respect to optimal values of CU, HR and fuel-mix, and (b) FC_2, fuel cost corresponding to optimal values of HR and fuel-mix for the observed CU if it is taken to be optimal.
(iii) Operational inefficiency : It is the difference between (a) FC_3, fuel cost computed for actual average values of CU, HR and fuel-mix, and (b) FC_2 above.

Kothagudam (A), a 240 MW power plant, has system inefficiency of the order of 2.7 paise in relation to average CC/kWh (12.5 paise). The corresponding other cost components of inefficiencies are (in paise) :

CC_1 = 13.79, CC_2 = 11.46
FC_1 = 14.69, FC_2 = 18.56
FC_3 = 22.17, FC(observed) = 22.00

Hence, the measures of inefficiencies are (in paise), capital cost component of planning inefficiency (2.33), fuel cost component of planning inefficiency (3.87), and operational inefficiency (3.61).

Indraprastha power station (IC = 284.1 MW) has the following estimates : System inefficiency is 4.61 paise in relation to the average capital cost/kWh (12 paise). Further,

CC_1 = 12.55, CC_2 = 9.74

FC_1 = 16.96, FC_2 = 18.63

FC_3 = 20.63, FC = 19.90

Consequently, inefficiency estimates can be derived to be (in paise) :

Capital cost component of planning inefficiency = 2.81,
Fuel cost component of planning inefficiency = 1.67, and
Operational inefficiency = 2.0.

Durgapur Coke-Oven Plant, belonging to Durgapur Power Projects Limited, has an estimate of system inefficiency equal to 4.65 paise as compared to the average capital cost per kWh (8 paise).

The other cost components obtained from our methodology are :

CC_1 = 7.56, CC_2 = 5.76

FC_1 = 22.64, FC_2 = 24.82

FC_3 = 28.10, FC(observed) = 24.00.

Thus, the inefficiency measures turned out to be (in paise):

Capital cost component of planning inefficiency = 1.8,
Fuel cost component of planning inefficiency = 2.18, and
Operational inefficiency = 3.28.

For the Panipat Power Plant, we estimated the system inefficiency to be 2.61 as compared to the average capital cost per kWh which is 15 paise. The other cost components of inefficiencies are :

$CC_1 = 15.76$, $CC_2 = 10.22$
$FC_1 = 27.76$, $FC_2 = 37.22$
$FC_3 = 39.74$, $FC(\text{observed}) = 39.0$.

Hence, the measures of inefficiencies can be computed to be (in paise) :

Capital cost component of planning inefficiency = 5.54,
Fuel cost component of planning inefficiency = 9.46, and
Operational inefficiency = 2.52.

The results obtained so far are summarized in Table 7.11. Computations for Paras, Parli Vaijnatu and Ramagundam (B) are along similar lines.

We do not rely much on these cost implications of inefficiencies. Firstly, because the relative flat shape of the cost curves at the minimum makes the distinction between fuel cost component of planning inefficiency and operational

TABLE 7.11

DETERMINISTIC MODEL : COST IMPLICATIONS OF MEASURES OF INEFFICIENCY

Sl. No.	Name of the Power Plant	Capital cost/kWh (paise)	System inefficiency (paise)	Capital cost component of Planning Inefficiency (paise)	Fuel cost/kWh(paise)	Fuel cost component of Planning Inefficiency (paise)	Operational Inefficiency (paise)
1.	Paras	3.60	13.05	0.19	14.00	1.02	0.65
2.	Parli Vaijnatu	7.80	18.76	0.57	10.70	1.08	0.07
3.	Kothagudam(A)	12.50	2.70	2.33	22.00	3.87	3.61
4.	Ramagundam(B)	7.50	18.27	0.12	17.30	0.23	0.12
5.	Panipat	15.00	2.61	5.54	39.00	9.46	2.52
6.	Durgapur Power Projects	8.00	4.65	1.80	24.00	2.18	3.28
7.	Indraprastha	12.00	4.61	2.81	19.50	1.67	2.00

inefficiency a bit dubious. Secondly, capital and fuel cost implications of different units within a plant are not unambiguous. A heuristic deflator which may capture unit level cost characterisation from a given information of a plant, may not provide the desired results due to diversified technological constraints attributable to non-identical unit sizes.

Moreover, one may seek to explore the possibility of estimating the measures of planning, system and operational inefficiencies in the face of demand and production uncertainties caused by the random fluctuations of customer demand (comprising household, industrial and commercial sector) and unpredictable outages of the capital equipment (i.e., boiler turbine generator, BTG set). This will be attempted in Chapter 8.

It may be mentioned that though inefficiency measures in physical terms do give rise to a speculation that the operational inefficiency predominates over other variants, the cost implications have results which are mixed in nature. One can notice that for small plants, e.g., Paras, Parli Vaijnatu and Ramagundam (B), the measure of system inefficiency may be biased upward due to the sensitivity of the cross-section peak load quarter estimate of the capital cost equation with respect to lower value of installed capacity.

7.6 CONCLUSION

From the foregoing analysis it is clear that

(i) the planning inefficiency in terms of capacity utilization rate is prominent among relatively aged power plants irrespective of their sizes.

(ii) the planning inefficiency as carried over to the operational level is distinguishable from operational inefficiency only when the flatness of average cost curves is not indicated.

(iii) the operational inefficiency, except in few well-managed and new power plants, is significantly large in magnitude. The results of the cost implications are, however, mixed in nature.

(iv) the fuel cost equation yields, on an average, optimal fuel-mix which is quite far off from the actual monthly average over the entire period of study. It may be noted that the general policy prescription is either to reduce the overall consumption of individual fuels or to substitute furnace oil, light diesel oil, or natural gas for coal, lignite, or residual fuel oil (e.g., LSHS or HSHS).

Thus, the estimates based on the deterministic variant of the model exhibited ex ante fuel substitution across firms in the peak load quarter and ex post fuel substitution within a given production unit in the time series set up. The pertinent interdependent hierarchical structure of decision

making has been identified with consequent quantification of the extent of measures of inefficiencies at the planning, system and operational levels.

The stochastic counterpart of the model and month-wise computer simulation of operational performance will be attempted in subsequent chapters, to sharpen the results so obtained.

CHAPTER 8

STOCHASTIC MODEL : TIME SERIES ANALYSIS

8.1 INTRODUCTION

Once the process of steam electric power generation is open to random variations in demand and production over the days of a week, months of a season and quarters of a year, the power plant management has to adapt its decision making strategy to overcome the exogenous uncertainties by prescribing appropriate policy measures. The hierarchical structure of the decision making becomes cautious in allocating production and operating expenses optimally among different stages of production.

The repair and the operations and maintenance (OM) costs can no longer be treated as fixed costs and the concept of variable cost, other than the pure fuel cost, becomes an important aspect of the decision making as advocated in Chapter 4. The sensitivity of the process variables in production planning is adequately taken into consideration by utilizing appropriate cost structure specifications.

The plant load factor (PLF) (which is an index of demand uncertainty) and forced outage rate (FOR) (an index of production uncertainty) enter the capital cost (CC/kWh) equation in the stochastic model.

TABLE 8.1

STOCHASTIC MODEL: SYSTEM OF NON-LINEAR EQUATIONS ESTIMATED FOR POWER PLANTS

<u>GURUNANAKDEB (BHATINDA) :</u>

(JANUARY 1980 - MARCH 1981)

$$C_3 = -120.24 + \underset{(2.43)}{1.06}(PUR) + \underset{(2.28)}{4170.76}(1/PUR) + \underset{(2.28)}{0.00041}(PUR)(FOR)$$

$$-\underset{(2.64)}{0.0028}(PUR)(PLF),\ \bar{R}^2 = 0.97,\ DW = 1.12$$

$$C_4 = 56.51 - \underset{(3.81)}{1.57}(CU) + \underset{(2.46)}{0.013}(CU)^2 + \underset{(2.90)}{0.00066}(CU)(FOR)$$

$$-\underset{(2.63)}{0.00041}(CU)(PLF) - \underset{(2.76)}{0.001}(CU)(PUR),\ \bar{R}^2 = 0.93,\ DW = 2.29$$

<u>FARIDABAD :</u>

(JANUARY 1980 - JUNE 1981)

$$C_3 = 32.15 - \underset{(2.77)}{1.72}(PUR) + \underset{(1.67)}{0.0093}(PUR)^2 - \underset{(1.89)}{0.0014}(PUR)(PLF)$$

$$+\underset{(2.87)}{0.026}(PUR)(FOR),\ \bar{R}^2 = 0.90,\ DW = 2.42$$

$$C_4 = 57.14 - \underset{(8.43)}{4.24}(CU) + \underset{(6.31)}{0.049}(CU)^2 + \underset{(1.61)}{0.016}(CU)(PUR),\ \bar{R}^2 = 0.89, DW = 1.77$$

<u>PANIPAT :</u>

(APRIL 1980 - JUNE 1981)

$$C_3 = -2418.09 + \underset{(1.70)}{13.53}(PUR) + \underset{(1.61)}{108329.91}(1/PUR) + \underset{(4.21)}{0.0028}(PUR)(FOR)$$

$$-\underset{(2.48)}{0.003}(PUR)(PLF),\ \bar{R}^2 = 0.89,\ DW = 0.80$$

$$C_4 = 85.08 - \underset{(3.48)}{3.09}(CU) + \underset{(1.84)}{0.025}(CU)^2 - \underset{(3.04)}{0.016}(CU)(PLF)$$

$$+\underset{(2.50)}{0.0087}(CU)(PUR),\ \bar{R}^2 = 0.92,\ DW = 1.72$$

INDRAPRASTHA :

(OCTOBER 1979 - MARCH 1981)

$$C_3 = \underset{}{117.23}-\underset{(2.57)}{2.07}(PUR)+\underset{(2.62)}{0.01}(PUR)^2-\underset{(2.22)}{0.00032}(PUR)(PLF)$$

$$+\underset{(1.63)}{0.0035}(PUR)(FOR),\ \bar{R}^2=0.90,\ DW = 0.89$$

$$C_4 = 57.42-\underset{(1.67)}{1.07}(CU)+\underset{(1.96)}{0.0068}(CU)^2-\underset{(2.23)}{0.0017}(CU)(PLF)$$

$$+\underset{(2.20)}{0.00098}(CU)(FOR)+\underset{(2.42)}{0.0011}(CU)(PUR),\ \bar{R}^2=0.98,\ DW=1.23$$

BADARPUR (NTPC) :

(JANUARY 1981 - MARCH 1982)

$$C_3 = 68.72-\underset{(2.76)}{1.71}(PUR)+\underset{(2.52)}{0.012}(PUR)^2-\underset{(2.39)}{0.00025}(PUR)(PLF)$$

$$+\underset{(4.40)}{0.0028}(PUR)(FOR),\ \bar{R}^2=0.90,\ DW = 1.20.$$

$$C_4 = 134.18-\underset{(2.14)}{4.06}(CU)+\underset{(2.45)}{0.023}(CU)^2-\underset{(2.09)}{0.0027}(CU)(PUR)-\underset{(2.64)}{0.00078}(CU)(PLF)$$

$$+\underset{(2.58)}{0.032}(CU)(FOR),\ \bar{R}^2=0.89,\ DW = 1.67$$

NASIK :

(JANUARY 1980 - MARCH 1981)

$$C_3 = -32.39+\underset{(8.69)}{0.31}(PUR)+\underset{(9.94)}{1770.03}(1/PUR)+\underset{(1.41)}{0.000084}(PUR)(FOR)$$

$$-\underset{(9.74)}{0.00072}(PUR)(PLF),\ \bar{R}^2=0.99,\ DW=1.55$$

$$C_4 = 17.71-\underset{(19.21)}{0.41}(CU)+\underset{(17.93)}{0.0022}(CU)^2+\underset{(1.59)}{0.000023}(CU)(FOR)$$

$$+\underset{(5.04)}{0.00054}(CU)(PUR),\ \bar{R}^2=0.99,\ DW = 1.78.$$

BHUSAWAL (I) :

(JANUARY 1980 - MARCH 1981)

$$C_3 = \underset{}{73.64}-\underset{(8.58)}{1.22}(PUR)+\underset{(7.81)}{0.0082}(PUR)^2-\underset{(3.20)}{0.0031}(PUR)(FOR)$$

$$-\underset{(5.45)}{0.0025}(PUR)(PLF),\ \bar{R}^2=0.89,\ DW=2.39$$

$$C_4 = 35.03-\underset{(7.94)}{0.79}(CU)+\underset{(5.95)}{0.0051}(CU)^2-\underset{(2.19)}{0.0011}(CU)(FOR)$$

$$+\underset{(1.84)}{0.00026}(CU)(PUR),\ \bar{R}^2=0.93,\ DW=1.47$$

BHUSAWAL (II) :

(APRIL 1980 - MARCH 1981)

$$C_3 = 22.07-\underset{(2.00)}{0.031}(PUR)+\underset{(1.94)}{0.00024}(PUR)^2+\underset{(1.70)}{0.000096}(PUR)(FOR)$$

$$-\underset{(1.87)}{0.000072}(PUR)(PLF),\ \bar{R}^2=0.92,\ DW=0.80$$

$$C_4 = 18.85-\underset{(2.28)}{0.53}(CU)+\underset{(1.80)}{0.0045}(CU)^2-\underset{(2.43)}{0.00056}(CU)(PUR)$$

$$-\underset{(2.19)}{0.000094}(CU)(PLF),\ \bar{R}^2=0.97,\ DW = 1.02$$

PARAS :

(JANUARY 1980 - MARCH 1981)

$$C_3 = 22.36-\underset{(2.67)}{0.065}(PUR)+\underset{(2.01)}{0.00033}(PUR)^2+\underset{(2.54)}{0.00039}(PUR)(FOR)$$

$$-\underset{(2.69)}{0.00023}(PUR)(PLF),\ \bar{R}^2=0.77,\ DW = 1.70$$

$$C_4 = 22.61-\underset{(3.93)}{0.53}(CU)+\underset{(2.48)}{0.0024}(CU)^2+\underset{(1.43)}{0.000051}(CU)(FOR)$$

$$+\underset{(1.80)}{0.0012}(CU)(PUR),\ \bar{R}^2 = 0.82,\ DW=1.87$$

KORADI :

(JANUARY 1980 - MARCH 1981)

$$C_3 = -20.32+\underset{(2.49)}{0.25(PUR)}+\underset{(1.73)}{1263.75(1/PUR)}+\underset{(5.29)}{0.0011(PUR)(FOR)},$$

$$\bar{R}^2 = 0.75, \ DW = 2.34$$

$$C_4 = 23.69-\underset{(1.72)}{0.61(CU)}+\underset{(1.73)}{0.0048(CU)^2}+\underset{(1.90)}{0.0017(CU)(PUR)}$$

$$-\underset{(1.82)}{0.00093(CU)(PLF)}, \ \bar{R}^2=0.63, \ DW=0.99$$

PARLI VAIJNATU :

(JANUARY 1980 - MARCH 1981)

$$C_3 = 14.66-\underset{(4.38)}{0.17(PUR)}+\underset{(2.00)}{0.00077(PUR)^2}-\underset{(1.42)}{0.00042(PUR)(FOR)}$$

$$+\underset{(3.42)}{0.00081(PUR)(PLF)}, \ \bar{R}^2=0.84, \ DW=2.18$$

$$C_4=28.29-\underset{(6.64)}{0.24(CU)}+\underset{(2.52)}{0.00079(CU)^2}-\underset{(10.28)}{0.0015(CU)(PUR)}, \ \bar{R}^2=0.93, DW=2.28$$

TROMBAY (TATA) :

(OCTOBER 1979 - MARCH 1981)

$$C3=348.35-\underset{(3.71)}{6.4(PUR)}+\underset{(3.25)}{0.035(PUR)^2}-\underset{(1.49)}{0.0058(PUR)(PLF)}$$

$$+\underset{(2.38)}{0.0088(PUR)(FOR)}, \ \bar{R}^2=0.85, \ DW=0.91$$

$$C_4 = 280.97-\underset{(4.61)}{6.13(CU)}+\underset{(4.78)}{0.056(CU)^2}-\underset{(1.78)}{0.0085(CU)(PLF)}$$

$$-\underset{(2.55)}{0.013(CU)(PUR)}, \ \bar{R}^2=0.90, \ DW=1.17$$

DHUVARAN :

(OCTOBER 1979 - MARCH 1981)

$$C_3 = 30.23 - \underset{(1.75)}{0.27}(PUR) + \underset{(1.85)}{0.0016}(PUR)^2 + \underset{(1.90)}{0.000012}(PUR)(PLF) - \underset{(6.54)}{0.00026}(PUR)(FOR), \quad \bar{R}^2 = 0.92, \quad DW = 1.62$$

$$C_4 = 7.12 - \underset{(1.69)}{0.083}(CU) + \underset{(1.46)}{0.00048}(CU)^2 - \underset{(3.05)}{0.000081}(CU)(PUR), \quad \bar{R}^2 = 0.89, \quad DW = 1.23$$

UKAI :

(OCTOBER 1979 - JUNE 1981)

$$C_3 = 23.41 - \underset{(2.11)}{0.24}(PUR) + \underset{(1.98)}{0.0022}(PUR)^2 - \underset{(2.23)}{0.0013}(PUR)(FOR), \quad \bar{R}^2 = 0.94, \quad DW = 1.31$$

$$C_4 = 37.03 - \underset{(2.78)}{1.53}(CU) + \underset{(1.71)}{0.013}(CU)^2 + \underset{(2.55)}{0.0078}(CU)(PLF) - \underset{(2.12)}{0.0032}(CU)(PUR), \quad \bar{R}^2 = 0.78, \quad DW = 1.22$$

KOTHAGUDAM(A) :

(JANUARY 1980 - MARCH 1981)

$$C_3 = 67.39 - \underset{(2.97)}{0.76}(PUR) + \underset{(2.13)}{0.0078}(PUR)^2 + \underset{(1.78)}{0.0018}(PUR)(FOR) - \underset{(6.44)}{0.005}(PUR)(PLF), \quad \bar{R}^2 = 0.89, \quad DW = 1.86$$

$$C_4 = 48.56 - \underset{(4.31)}{1.14}(CU) + \underset{(3.81)}{0.009}(CU)^2 + \underset{(2.60)}{0.00054}(CU)(FOR) - \underset{(1.85)}{0.00047}(CU)(PUR) - \underset{(1.72)}{0.00079}(CU)(PLF), \quad \bar{R}^2 = 0.98, \quad DW = 1.97$$

KOTHAGUDAM(B) :

(APRIL 1980 - MARCH 1981)

$$C_3=130.31-\underset{(1.67)}{45.72}(PUR)+\underset{(1.65)}{0.49}(PUR)^2+\underset{(2.68)}{0.018}(PUR)(FOR)$$

$$-\underset{(2.77)}{0.014}(PUR)(PLF),\ \bar{R}^2=0.93,\ DW=1.61$$

$$C_4=161.95-\underset{(6.93)}{9.6}(CU)+\underset{(6.17)}{0.1}(CU)^2-\underset{(2.61)}{0.011}(CU)(PLF)$$

$$+\underset{(2.05)}{0.00055}(CU)(PUR)+\underset{(2.20)}{0.015}(CU)(FOR),\ \bar{R}^2=0.90,\ DW=1.55$$

KOTHAGUDAM(C) :

(JANUARY 1980 - MARCH 1981)

$$C_3 = 350.5-\underset{(1.81)}{50.25}(PUR)+\underset{(1.79)}{0.54}(PUR)^2+\underset{(2.84)}{0.019}(PUR)(FOR)$$

$$-\underset{(2.80)}{0.014}(PUR)(PLF),\ \bar{R}^2=0.95,\ DW=1.59$$

$$C_4 = 198.44-\underset{(6.79)}{9.20}(CU)+\underset{(5.91)}{0.096}(CU)^2-\underset{(1.61)}{0.011}(CU)(PLF)$$

$$+\underset{(2.18)}{0.002}(CU)(PUR)+\underset{(2.19)}{0.014}(CU)(FOR),\ \bar{R}^2=0.89, DW=1.16$$

RAMAGUNDAM(B) :

(JANUARY 1980 - MARCH 1981)

$$C_3=9.57+\underset{(2.15)}{0.23}(PUR)+\underset{(2.17)}{942.97}(1/PUR)+\underset{(2.63)}{0.002}(PUR)(FOR)$$

$$-\underset{(2.04)}{0.00057}(PUR)(PLF),\ \bar{R}^2=0.97,\ DW=2.45$$

$$C_4 = 83.98-\underset{(1.65)}{2.08}(CU)+\underset{(2.02)}{0.014}(CU)^2-\underset{(1.68)}{0.00098}(CU)(PUR)$$

$$-\underset{(2.81)}{0.00016}(CU)(PLF)+\underset{(2.03)}{0.021}(CU)(FOR),\ \bar{R}^2=0.93,\ DW=1.81$$

NEYVELI LIGNITE CORPORATION :

(APRIL 1980 - DECEMBER 1981)

$$C_3 = -50.96 + \underset{(2.18)}{0.57}(PUR) + \underset{(2.19)}{2666.33}(1/PUR) + \underset{(3.02)}{0.00079}(PUR)(FOR)$$

$$-\underset{(2.11)}{0.00067}(PUR)(PLF),\ \bar{R}^2=0.90,\ DW = 1.46$$

$$C_4 = 20.30 - \underset{(5.27)}{0.3}(CU) + \underset{(3.22)}{0.0017}(CU)^2 - \underset{(2.59)}{0.000078}(CU)(PLF)$$

$$+\underset{(2.49)}{0.00022}(CU)(PUR) + \underset{(2.76)}{0.00014}(CU)(FOR),\ \bar{R}^2=0.97,\ DW=2.73$$

ENNORE :

(OCTOBER 1979 - MARCH 1981)

$$C_3 = 64.2 - \underset{(1.73)}{0.84}(PUR) + \underset{(1.83)}{0.006}(PUR)^2 - \underset{(4.72)}{0.0063}(PUR)(FOR),\ \bar{R}^2=0.82, DW=1.83$$

$$C_4 = -23.55 + \underset{(1.80)}{0.39}(CU) + \underset{(10.14)}{885.42}(1/CU) - \underset{(1.90)}{0.00077}(CU)(PUR)$$

$$-\underset{(2.20)}{0.0027}(CU)(PLF),\ \bar{R}^2=0.99,\ DW=2.38$$

BASIN BRIDGE :

(APRIL 1980 - MARCH 1981)

$$C_3 = 48.08 - \underset{(2.14)}{0.58}(PUR) + \underset{(2.16)}{0.0047}(PUR)^2 + \underset{(5.57)}{0.0018}(PUR)(FOR)$$

$$-\underset{(2.28)}{0.00066}(PUR)(PLF),\ \bar{R}^2=0.90,\ DW=1.50$$

$$C_4 = 27.86 - \underset{(2.31)}{0.68}(CU) + \underset{(2.79)}{0.0043}(CU)^2 + \underset{(2.88)}{0.001}(CU)(FOR)$$

$$+\underset{(2.08)}{0.0018}(CU)(PUR) - \underset{(2.78)}{0.00062}(CU)(PLF),\ \bar{R}^2=0.97, DW=2.32$$

PANKI :

(JANUARY 1980 - JUNE 1981)

$$C_3=126.47-\underset{(2.25)}{2.6}(PUR)+\underset{(1.95)}{0.012}(PUR)^2+\underset{(5.47)}{0.0025}(PUR)(PLF)$$

$$+\underset{(2.63)}{0.013}(PUR)(FOR),\ \bar{R}^2=0.81,\ DW=1.56$$

$$C_4=44.85-\underset{(12.67)}{1.01}(CU)+\underset{(6.53)}{0.0081}(CU)^2-\underset{(1.50)}{0.001}(CU)(PUR),\ \bar{R}^2=0.98, DW=2.46$$

HARDUAGANJ (B) :

(APRIL 1980 - MARCH 1981)

$$C_3=67.9-\underset{(1.85)}{1.45}(PUR)+\underset{(1.88)}{0.011}(PUR)^2-\underset{(2.51)}{0.00053}(PUR)(PLF)$$

$$+\underset{(2.70)}{0.0022}(PUR)(FOR),\ \bar{R}^2=0.92,\ DW=1.87$$

$$C_4=48.56-\underset{(1.70)}{1.35}(CU)+\underset{(2.28)}{0.012}(CU)^2-\underset{(2.08)}{0.00017}(CU)(PLF)$$

$$+\underset{(2.44)}{0.00057}(CU)(FOR)-\underset{(2.01)}{0.0025}(CU)(PUR),\ \bar{R}^2=0.98,\ DW=1.97$$

HARDUAGANJ (C) :

(APRIL 1980 - MARCH 1981)

$$C_3 = 68.66-\underset{(2.17)}{1.69}(PUR)+\underset{(2.15)}{0.013}(PUR)^2-\underset{(2.25)}{0.00024}(PUR)(PLF)$$

$$+\underset{(1.79)}{0.0012}(PUR)(FOR),\ \bar{R}^2=0.95,\ DW=1.21$$

$$C_4 = 106.16-\underset{(2.49)}{4.99}(CU)+\underset{(1.80)}{0.036}(CU)^2-\underset{(1.72)}{0.0075}(CU)(PLF)$$

$$+\underset{(2.69)}{0.017}(CU)(PUR)+\underset{(2.03)}{0.000098}(CU)(FOR),\ \bar{R}^2=0.92,\ DW=1.62$$

<u>BARAUNI :</u>

(JANUARY 1980 – MARCH 1981)

$$C_3=351.39-\underset{(3.77)}{10.17}(PUR)+\underset{(3.27)}{0.078}(PUR)^2-\underset{(1.48)}{0.000085}(PUR)(FOR),$$

$$\bar{R}^2 = 0.73,\ DW=1.84$$

$$C_4=145.62-\underset{(13.70)}{7.55}(CU)+\underset{(11.48)}{0.11}(CU)^2-\underset{(3.53)}{0.005}(CU)(FOR)-\underset{(2.91)}{0.0041}(CU)(PUR)$$

$$-\underset{(1.68)}{0.0034}(CU)(PLF),\ \bar{R}^2=0.99,\ DW=2.29$$

<u>DURGAPUR POWER PROJECTS LTD. :</u>

(APRIL 1980 – MARCH 1981)

$$C_3=41.37-\underset{(2.33)}{1.12}(PUR)+\underset{(2.31)}{0.014}(PUR)^2+\underset{(5.56)}{0.0029}(PUR)(FOR)$$

$$-\underset{(2.19)}{0.00095}(PUR)(PLF),\ \bar{R}^2=0.82,\ DW=1.46$$

$$C_4 = 23.87-\underset{(2.42)}{0.93}(CU)+\underset{(1.85)}{0.012}(CU)^2+\underset{(1.90)}{0.0015}(CU)(FOR)$$

$$-\underset{(2.49)}{0.00095}(CU)(PUR)-\underset{(2.79)}{0.00072}(CU)(PLF),\ \bar{R}^2=0.89,\ DW=1.41$$

The optimal CU's are computed from the estimated equations. Results are in Table 8.2. Calculations of CU are performed both with respect to observed PUR and optimal PUR for exogenous values of FOR and PLF. The optimal values are, in general, far off from their observed counterparts. The deterministic solutions are also tabulated for comparison. Once again, small power plants, e.g., Bhusawal (I) (IC = 62.5 MW), Parli Vaijnatu (IC = 60 MW), and Ramagundam(B) (IC = 62.5 MW), are doing well in executing capacity utilization along the optimal path. Since PUR's, as reported by different power plants, lack proper planning, we should concentrate our comparison of CU with respect to optimal PUR derived from the prescribed model. Among large plants, such as, Faridabad (IC = 120 MW), Trombay (Tata) (IC = 337.5 MW), and Koradi (IC = 680 MW), the observed CU is quite comparable to the optimal magnitudes.

It may, however, be noted that for a given anticipated non-optimal PUR, the actual CU delivered is higher than the corresponding optimal value (see the relevant figures for Faridabad, Parli Vaijnatu, and Koradi power stations). Thus, it is essential to ensure the optimality of PUR to establish a reliable estimate of the capacity utilization rate. Moreover, in the stochastic model, the calculations are more realistic than the deterministic variant of the proposed methodology. For, the very existence of forced outage rate has been able to restrict the availability factor which

TABLE 8.2

DETERMINISTIC AND STOCHASTIC MODELS: OPTIMAL CALCULATIONS OF CU

Sl. No.	Name of the Power Plant	IC (MW)	CU (observed) (percentage)	CU (optimal) (Deterministic) (percentage)	CU (at observed PUR)(optimal) (Stochastic) (percentage)	CU (at optimal PUR)(optimal) (stochastic) (percentage)
1	2	3	4	5	6	7
1.	Gurunanakdeb (Bhatinda)	440.00	36.27	54.88	62.50	61.60
2.	Faridabad	120.00	33.62	43.06	28.76	34.30
3.	Panipat	220.00	34.06	51.86	59.60	62.19
4.	Indraprastha	284.10	63.81	86.57	80.51	81.35
5.	Badarpur	510.00	49.96	66.96	77.14	76.26
6.	Nasik	280.00	63.84	81.67	82.47	83.80
7.	Bhusawal (I)	62.50	73.00	79.89	76.23	76.77
8.	Bhusawal (II)	210.00	43.16	58.69	64.16	63.26
9.	Paras	92.50	64.85	72.55	91.54	93.61
10.	Koradi	680.00	59.11	61.53	55.19	59.53

contd ...

1.	2.	3.	4.	5.	6.	7.
11.	Parli Vaijnatu	60.00	85.83	94.34	72.59	89.52
12.	Trombay (Tata)	337.50	68.49	80.46	70.87	72.55
13.	Dhuvaran	534.00	69.64	99.54	94.35	93.42
14.	Ukai	640.00	37.50	47.03	54.14	50.63
15.	Kothagudam (A)	240.00	50.21	67.27	69.33	69.02
16.	Kothagudam (B)	220.00	21.52	41.37	46.16	46.28
17.	Kothagudam (C)	220.00	32.29	41.33	46.50	46.92
18.	Ramagundam (B)	62.50	68.56	72.14	71.27	70.60
19.	Neyveli Lignite Corporation	600.00	61.01	77.30	84.97	86.03

contd ...

1.	2.	3.	4.	5.	6.	7.
20.	Ennore	450.00	36.79	61.80	71.92	72.65
21.	Basin Bridge	90.00	41.70	66.40	65.24	68.98
22.	Panki	284.00	51.05	74.38	69.06	69.08
23.	Harduaganj (B)	210.00	34.38	50.41	62.46	60.49
24.	Harduaganj (C)	170.00	36.41	65.30	55.88	59.82
25.	Barauni	145.00	25.79	36.09	38.86	38.66
26.	Durgapur Power Projects Ltd.	285.00	28.54	40.40	44.06	42.86

serves as a base to determine ex post capacity utilization rate.

Normally, we expect the coefficients of the interaction term (CU)(PUR) to be negative, that of (CU)(FOR) to be positive, and that of (CU) (PLF) to be negative as explained in Chapter 6. In time series analysis of individual power stations, we obtained all possible combinations of signs. The older power stations, with more than 30 percent forced outages, exhibited positive coefficients for the terms (CU)(PUR) and (CU)(PLF) which indicate that the persistence of diseconomies of scale is a consequence of unplanned maintenance and inefficient operational decisions[1].

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1. In the case of the Bhusawal (I) and the Barauni power plants, there was a negative sign for the coefficient of (CU)(FOR) which requires some clarification. Normally, it would be expected that for a given CU delivered an increase in FOR implies that the power plant is utilized for a longer time and hence the CC/kWh is higher. In both these plants there are small units being operated along with larger units. Further, the smaller units are so designed that they can use both coal and residual fuel oil to fire the boilers. This flexibility appears to create an advantage in favour of their use even if CC/kWh is high. Availability of RFO more than anything else may be the reason for this priority use even if it violates the usual merit-order loading. If now there is an increase in FOR in the smaller units there will be a loading of the larger units which reduce CC/kWh rather than increase it. There is, however, no documental evidence that this argument is valid. Our conversations with knowledgeable sources indicated that such things do happen. However, we cannot treat this as confirmed evidence.

8.3 VARIABLE COST EQUATION

In the presence of demand and production fluctuations, the utility (plant) managers decide about PUR on the basis of the variable cost, C_3, which is the sum total of the fuel cost, the repair cost and the operations and maintenance (OM) costs. The concept of variable cost adds a new dimension o the hierarchical structure of the decision making in steam electric power generation. The planned utilization rate (PUR) is derived from the concept of planned outage rate (POR) which reflects the needs for preventive and periodic maintenance of the capital equipment, i.e., boiler turbine generator (BTG) set. Further, it is possible to distinguish the *ex ante* decision variable (PUR) from the *ex post* magnitude of CU actually delivered at the bus-bars.

The estimated variable cost per kWh (C_3) equations are reported in Table 8.1. They generally contain PUR, (PUR^2, or 1/PUR), cross terms (PUR)(PLF) and (PUR)(FOR) as independent variables. The numbers in the parentheses represent the t-values of the associated coefficients. The $\bar{R}^2$ and DW statistics are also indicated.

The optimum PUR's are computed and reported in Table 8.3 for all power plants in the sample. The actual observed PUR along with the installed capacity, PLF and FOR

TABLE 8.3

STOCHASTIC MODEL: OPTIMAL CALCULATIONS OF PUR WITH EXOGENOUS PLF AND FOR

Sl. No.	Name of the Power Plant	IC (MW)	PLF (observed)	FOR (observed)	PUR (observed)	PUR (optimal)
1	2	3	4	5	6	7
1.	Gurunanakdeb (Bhatinda)	440.00	53.50	33.18	90.38	67.06
2.	Faridabad	120.00	40.42	29.10	88.91	54.33
3.	Panipat	220.00	44.21	32.54	97.04	59.33
4.	Indraprastha	284.10	72.96	16.03	88.71	78.25
5.	Badarpur	510.00	52.16	22.25	86.70	71.49
6.	Nasik	280.00	75.81	10.01	93.63	82.89
7.	Bhusawal (I)	62.50	74.05	5.81	83.19	61.78
8.	Bhusawal (II)	210.00	45.50	22.00	81.57	67.19
9.	Paras	92.50	71.38	4.36	83.82	75.37

contd ...

1.	2.	3.	4.	5.	6.	7.
10.	Koradi	680.00	89.06	13.34	93.09	69.22
11.	Parli Vaijnatu	60.00	88.38	4.73	83.19	65.80
12.	Trombay (Tata)	337.50	81.13	2.95	82.64	96.67
13.	Dhuvaran	534.00	75.63	2.24	95.62	84.55
14.	Ukai	640.00	57.42	34.05	94.15	65.91
15.	Kothagudam(A)	240.00	75.96	3.45	84.05	72.62
16.	Kothagudam(B)	220.00	54.30	48.18	90.59	46.50
17.	Kothagudam(C)	220.00	62.05	52.83	85.91	46.42
18.	Ramagundam(B)	62.50	71.42	5.71	88.03	68.35
19.	Neyveli Lignite Corporation	600.00	80.37	9.48	88.06	71.53
20.	Ennore	450.00	60.81	19.26	75.68	80.11

contd...

1.	2.	3.	4.	5.	6.	7.
21.	Basin Bridge	90.00	68.13	3.97	83.33	65.52
22.	Panki	284.00	66.51	17.30	94.07	82.37
23.	Harduaganj(B)	210.00	54.51	36.37	81.74	62.39
24.	Harduaganj(C)	170.00	56.54	34.87	81.34	64.17
25.	Barauni	145.00	57.85	33.14	75.00	64.84
26.	Durgapur Power Projects Ltd.	285.00	64.71	14.29	70.22	40.87

NOTE : All figures other than IC are expressed in percentages .

are tabulated for comparison. Except for the Trombay (Tata) (IC = 337.5 MW) and Ennore (IC = 450 MW) power stations, the optimal PUR's are far short of their observed magnitudes. This implies inappropriate planning at the operational level. Dhuvaran (IC = 534 MW), the multi-fuel plant, and Nasik (IC = 280 MW) have performed better in comparison to others reported in the sample. The interpretation of the cross term (PUR) (PLF) is analogous to that of (CU)(PLF) discussed earlier[2].

8.4 FUEL COST EQUATION

The fuel cost equation serves as a linking equation between the deterministic and stochastic model formulation. The uncertainty parameters are adequately taken care of in the capital cost and variable cost per kWh equations. What remains is the determination of HR and the resulting fuel combinations on the basis of fuel cost (deflated) alone. Thus the same estimated best fit equations for individual power plants are used in arriving at the optimum HR and fuel-mix. We have to go back to Table 7.1 to obtain C_2

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2. The interpretation of the coefficient of (PUR)(FOR) created a problem similar to the one encountered in footnote 1. It appears that the same argument holds even in this context.

equations estimated from time series analysis. The notable feature is the explicit incorporation of physical fuel quantities in ratios along with the index of output (i.e., HR) in the average cost function. The essential non-linearities, exhibited by HR and fuel-mix, are also demonstrated. The cost minimizing solutions of fuel quantities and fuel ratios are summarized in Tables 8.4 - 8.10. Optimum configurations are reported for both the case of the optimal PUR and the observed PUR for comparisons. We shall discuss the discrepancies between those computations in the next section in the light of measures of inefficiency in physical terms.

The optimal fuel quantities in coal-fired and oil/lignite-fired power plants are not glaringly different, though somewhat closer to the actuals when compared with the deterministic solutions. This result was obtained for the smaller as well as the larger plant sizes. For instance, among the small plants, Parli (IC = 60 MW), and Ramagundam (B) (IC = 62.5 MW) exhibited this result. Among the relatively larger stations Gurunanakdeb (Bhatinda) (IC = 440 MW), Indraprastha (IC = 284.1 MW), Trombay (Tata) (IC = 337.5 MW) and Dhuvaran (IC = 534 MW) have actual HR's and corresponding fuel combinations which are quite comparable to the optimal magnitudes.

TABLE 8.4

DETERMINISTIC AND STOCHASTIC MODELS: OPTIMAL CALCULATIONS OF HR

Sl.No.	Name of the Power Plant	IC (MW)	HR (observed)	HR (optimal) (deterministic)	HR(optimal) (stochastic) (at PUR observed)	HR(optimal) (stochastic) (at PUR optimal)
1	2	3	4	5	6	7
1.	Gurunanakdeb (Bhatinda)	440.00	3081.88	2963.61	3047.07	3058.75
2.	Faridabad	120.00	3704.14	3031.24	2951.16	2981.45
3.	Panipat	220.00	4066.57	3616.10	3713.70	3748.21
4.	Indraprastha	284.10	3461.48	3424.91	3373.17	3380.19
5.	Badarpur	510.00	3417.32	3306.79	3505.75	3487.02
6.	Nasik	280.00	2531.32	2321.91	2321.84	2321.73
7.	Bhusawal(I)	62.50	3321.00	3241.52	3242.24	3242.13
8.	Bhusawal(II)	210.00	3229.20	2765.39	2778.06	2775.97
9.	Paras	92.50	3300.72	2822.31	3301.84	3370.18
10.	Koradi	680.00	2217.92	2198.75	1800.20	2045.77

contd ...

1.	2.	3.	4.	5.	6.	7.
11.	Parli Vaijnatu	60.00	3286.31	3206.34	3228.47	3213.45
12.	Trombay (Tata)	337.50	2978.67	2939.99	2941.49	2941.23
13.	Dhuvaran	534.00	2785.52	2646.88	2649.02	2649.41
14.	Ukai	640.00	3048.34	2429.32	2396.70	2412.65
15.	Kothagudam (A)	240.00	3114.92	3020.17	3020.46	3020.42
16.	Kothagudam (B)	220.00	3703.09	3511.09	3562.60	3563.91
17.	Kothagudam (C)	220.00	3301.63	3005.95	3031.67	3033.78
18.	Ramagundam (B)	62.50	2787.35	2682.64	2680.82	2679.44
19.	Neyveli Lignite Corporation	600.00	3405.18	2988.80	3046.08	3054.30
20.	Ennore	450.00	3236.94	3049.42	3037.80	3036.97
21.	Basin Bridge	90.00	4820.22	4282.24	4279.18	4289.07

contd ...

1.	2.	3.	4.	5.	6.	7.
22.	Panki	284.00	3629.40	2625.01	2651.59	2651.49
23.	Harduaganj (B)	210.00	3772.90	3400.98	3481.35	3467.78
24.	Harduaganj (C)	170.00	3456.51	3296.88	3231.01	3258.13
25.	Barauni	145.00	4262.99	3545.24	3516.17	3518.22
26.	Durgapur Power Projects Ltd.	285.00	3239.47	3060.67	3064.93	3062.26

NOTE : All figures other than IC are expressed in Kcal/kWh.

TABLE 8.5(a)

STOCHASTIC MODEL : FUEL-MIX COMPARISONS (COAL-FIRED POWER PLANTS)

Sl. No.	Name of the Power Plant	FO/CO (observed)	FO/CO (optimal)	LDO/CO (observed)	LDO/CO (optimal)
1	2	3	4	5	6
1.	Gurunanakdeb (Bhatinda)	0.058	0.12	0.011	0.011
2.	Faridabad	0.06	0.06	0.018	0.019
3.	Panipat	0.27	0.37	0.048	0.048
4.	Indraprastha	0.059	0.11	-	-
5.	Badarpur	0.078	0.15	0.0018	0.0018
6.	Nasik	0.019	0.019	0.01	0.0075
7.	Bhusawal (I)	0.02	0.033	0.0007	0.0007
8.	Bhusawal (II)	0.11	0.29	0.011	0.011
9.	Paras	0.0064	0.009	0.00043	0.00043
10.	Koradi	0.021	0.021	0.0092	0.026

contd ...

1.	2.	3.	4.	5.	6.
11.	Parli Vaijnatu	0.0038	0.0038	0.0013	0.0016
12.	Ukai	0.18	0.18	0.0069	0.0084
13.	Kothagudam (A)	0.017	0.035	-	-
14.	Kothagudam (B)	0.10	0.20	-	-
15.	Kothagudam (C)	0.12	0.25	-	-
16.	Ramagundam (B)	0.0081	0.013	0.0017	0.0017
17.	Ennore	0.091	0.088	0.0066	0.0066
18.	Basin Bridge	0.23	0.093	-	-
19.	Panki	0.011	0.011	0.032	0.044
20.	Harduaganj (B)	0.14	0.058	-	-
21.	Harduaganj (C)	0.052	0.12	-	-
22.	Barauni	0.16	0.12	0.012	0.012
23.	Durgapur Power Projects	0.10	0.25	-	-

TABLE 8.5(b)

STOCHASTIC MODEL : FUEL-MIX COMPARISONS (OIL AND LIGNITE FIRED POWER PLANT)

Sl. No.	Name of the Power Plants	NG/OIL (observed)	NG/OIL (optimal)	NG/RFO (observed)	NG/RFO (optimal)	LDO/RFO (observed)	LDO/RFO (optimal)	FO/LIG (observed)	FO/LIG (optimal)
1.	Trombay(Tata)	0.38	0.88	-	-	-	-	-	-
2.	Dhuvaran	-	-	0.059	0.062	0.016	0.034	-	-
3.	Neyveli Lignite Corporation	-	-	-	-	-	-	0.11	0.24

TABLE 8.6

DETERMINISTIC AND STOCHASTIC MODELS: OPTIMAL FUEL QUANTITIES (COAL-FIRED POWER PLANTS) (AT OBSERVED PUR)

Sl. No.	Name of the Power Plant	CO (observed)	CO(optimal) (deterministic)	CO (optimal) (stochastic)	FO (observed)	FO (optimal) (deterministic)	FO (optimal) (stochastic)	LDO (observed)	LDO (optimal) (deterministic)	LDO(optimal)(stochastic)
1	2	3	4	5	6	7	8	9	10	11
1.	Gurunanakdeb (Bhatinda)	2882.08	2626.87	2700.85	167.55	307.35	316.01	32.24	29.39	30.21
2.	Faridabad	3435.78	2810.35	2736.11	206.06	168.55	164.10	62.30	52.34	50.95
3.	Panipat	3072.02	2554.07	2623.00	845.82	938.38	963.70	148.73	123.65	127.00
4.	Indraprastha	3267.53	3079.00	3032.48	193.94	345.91	340.68	-	-	-
5.	Badarpur	3163.42	2875.06	3048.04	248.14	426.50	452.16	5.76	5.23	5.55
6.	Nasik	2458.43	2261.39	2261.33	47.24	43.46	43.46	25.64	17.06	17.06
7.	Bhusawal(I)	3253.33	3135.62	3136.32	65.30	103.61	103.64	2.37	2.29	2.29
8.	Bhusawal(II)	2873.73	2122.46	2132.18	322.77	618.78	621.62	32.70	31.46	24.26

contd ...

1.	2.	3.	4.	5.	6.	7.	8.	9.	10.	11.
9.	Paras	3278.27	2796.00	3271.05	21.04	25.11	29.37	1.42	1.21	1.41
10.	Koradi	2152.51	2100.05	1719.39	44.37	44.10	36.11	19.86	54.60	44.70
11.	Parli Vaijnatu	3189.91	3188.86	3220.81	12.28	12.28	12.40	4.20	5.20	5.25
12.	Ukai	2563.17	2040.11	2012.72	467.42	372.03	367.04	17.75	17.17	16.94
13.	Kothagudam(A)	3063.12	2917.82	2918.10	51.80	102.35	102.36	-	-	-
14.	Kothagudam(B)	3364.05	2927.83	2970.78	339.04	583.26	591.82	-	-	-
15.	Kothagudam(C)	2936.06	2413.04	2433.69	365.57	592.91	597.98	-	-	-
16.	Ramagundam(B)	2760.12	2643.58	2641.79	22.45	34.47	34.45	4.78	4.58	4.58
17.	Ennore	2948.79	2785.08	2774.46	268.66	245.93	244.99	19.49	18.41	18.34

contd ...

1.	2.	3.	4.	5.	6.	7.	8.	9.	10.	11.
18.	Basin Bridge	3918.43	3916.74	3913.94	901.78	365.50	365.24	-	-	-
19.	Panki	3501.57	2490.07	2515.29	36.98	26.29	26.56	113.07	108.64	109.74
20.	Harduaganj(B)	3317.90	3213.02	3288.94	455.00	187.96	192.41	-	-	-
21.	Harduaganj(C)	3286.23	2948.63	2889.72	170.28	348.25	341.29	-	-	-
22.	Barauni	3634.59	3128.66	3103.01	583.24	377.70	374.61	45.16	38.87	38.55
23.	Durgapur Power Projects	2945.78	2453.93	2457.34	293.69	606.74	607.59	-	-	-

NOTE : All figures are expressed as Kcal/kWh.

TABLE 8.7

OBSERVED FUEL QUANTITIES (OIL AND LIGNITE FIRED POWER PLANTS)

Sl. No.	Name of the Power Plant	NG (observed)	RFO (observed)	LIG (observed)	CO (observed)	FO (observed)	LDO (observed)
1.	Trombay(Tata)	806.11	2131.64	-	-	-	-
2.	Dhuvaran	117.61	1986.08	42.50	225.92	377.66	31.57
3.	Neyveli Lignite Corporation	-	-	3061.09	-	326.89	17.19

NOTE : All figures are expressed in Kcal/kWh.

TABLE 8.8

DETERMINISTIC AND STOCHASTIC MODELS: OPTIMAL FUEL QUANTITIES
(OIL AND LIGNITE FIRED POWER PLANTS)(AT OBSERVED PUR)

Fuel Quantities	Trombay (Tata)	Dhuvaran	Neyveli Lignite Corporation
Natural Gas (NG) (Optimal)(Deterministic)	1376.84	114.69	-
Natural Gas (NG) (Optimal)(Stochastic)	1377.54	114.78	-
Residual Fuel Oil (RFO) (Optimal)(Deterministic)	1563.15	1862.81	-
Residual Fuel Oil (RFO) (Optimal)(Stochastic)	1563.95	1864.31	-
Lignite (LIG) (Optimal)(Deterministic)	-	39.86	2395.35
Lignite (LIG) (Optimal)(Stochastic)	-	39.89	2441.26
Coal (CO) (Optimal)(Deterministic)	-	211.90	-
Coal (CO) (Optimal)(Stochastic)	-	212.07	-
Furnace Oil (FO) (Optimal)(Deterministic)	-	354.21	579.99
Furnace Oil (FO) (Optimal)(Stochastic)	-	354.50	591.11
Light Diesel Oil (LDO) (Optimal)(Deterministic)	-	63.42	13.46
Light Diesel Oil (LDO) (Optimal)(Stochastic)	-	63.47	13.71

NOTE : All figures are expressed in Kcal/kWh.

TABLE 8.9

DETERMINISTIC AND STOCHASTIC MODELS : OPTIMAL FUEL QUANTITIES (COAL-FIRED POWER PLANTS) (AT OPTIMAL PUR)

Sl. No.	Name of the Power Plant	CO (observed)	CO(optimal) (deterministic)	CO(optimal) (stochastic)	FO (observed)	FO(optimal) (deterministic)	FO (optimal) (stochastic)	LDO (observed)	LDO (optimal) (deterministic)	LDO(optimal) (stochastic)
1.	2.	3.	4.	5.	6.	7.	8.	9.	10.	11.
1.	Gurunanakdeb (Bhatinda)	2882.08	2626.87	2711.20	167.55	307.35	317.22	32.24	29.39	30.33
2.	Faridabad	3435.78	2810.35	2764.19	206.06	168.55	165.78	62.30	52.34	51.48
3.	Panipat	3072.02	2554.07	2647.38	845.82	938.38	972.66	148.73	123.65	128.17
4.	Indraprastha	3267.53	3079.00	3038.79	193.94	345.91	341.39	-	-	-
5.	Badarpur	3163.42	2875.06	3031.76	248.14	426.50	449.74	5.76	5.23	5.52
6.	Nasik	2458.43	2261.39	2261.22	47.24	43.46	43.45	25.64	17.06	17.05
7.	Bhusawal(I)	3253.33	3135.62	3136.21	65.30	103.61	103.63	2.37	2.29	2.29
8.	Bhusawal(II)	2873.73	2122.46	2130.58	322.77	618.78	621.15	32.70	31.46	24.24

contd ...

1.	2.	3.	4.	5.	6.	7.	8.	9.	10.	11.
9.	Paras	3278.27	2796.00	3338.76	21.04	25.11	29.98	1.42	1.21	1.44
10.	Koradi	2152.51	2100.05	1953.93	44.37	44.10	41.03	19.86	54.60	50.80
11.	Parli Vaijnatu	3189.91	3188.86	3195.93	12.28	12.28	12.31	4.20	5.20	5.21
12.	Ukai	2563.17	2040.11	2026.12	467.42	372.03	369.48	17.75	17.17	17.05
13.	Kothagudam(A)	3063.12	2917.82	2918.06	51.80	102.35	102.36	-	-	-
14.	Kothagudam(B)	3364.05	2927.83	2971.88	339.04	583.26	592.03	-	-	-
15.	Kothagudam(C)	2936.06	2413.04	2435.38	365.57	592.91	598.40	-	-	-
16.	Ramagundam(B)	2760.12	2643.58	2640.44	22.45	34.47	34.43	4.78	4.58	4.58
17.	Ennore	2948.79	2785.08	2773.71	268.66	245.93	244.93	19.49	18.41	18.34
18.	Basin Bridge	3918.43	3916.74	3922.98	901.78	365.50	366.09	-	-	-
19.	Panki	3501.57	2490.07	2515.20	36.98	26.29	26.56	113.07	108.64	109.74

contd ...

1.	2.	3.	4.	5.	6.	7.	8.	9.	10.	11.
20.	Harduaganj(B)	3317.90	3213.02	3276.13	455.00	187.96	191.65	-	-	-
21.	Harduaganj(C)	3286.23	2948.63	2913.97	170.28	348.25	344.16	-	-	-
22.	Barauni	3634.59	3128.66	3104.82	583.24	377.70	374.82	45.16	38.87	38.58
23.	Durgapur Power Projects	2945.78	2453.93	2455.20	293.69	606.74	607.06	-	-	-

NOTE : All figures are expressed as Kcal/kWh.

TABLE 8.10

DETERMINISTIC AND STOCHASTIC MODELS : OPTIMAL FUEL QUANTITIES

(OIL AND LIGNITE FIRED POWER PLANTS)(AT OPTIMAL PUR)

Fuel Quantities	Trombay (Tata)	Dhuvaran	Neyveli Lignite Corporation
Natural Gas (NG) (Optimal)(Deterministic)	1376.84	114.69	-
Natural Gas (NG) (Optimal)(Stochastic)	1377.41	114.79	-
Residual Fuel Oil (RFO) (Optimal)(Deterministic)	1563.15	1862.81	-
Residual Fuel Oil(RFO) (Optimal)(Stochastic)	1563.81	1864.59	-
Lignite (LIG) (Optimal)(Deterministic)	-	39.86	2395.35
Lignite (LIG) (Optimal) (Stochastic)	-	39.90	2447.84
Coal (CO) (Optimal)(Deterministic)	-	211.90	-
Coal (CO) (Optimal)(Stochastic)	-	212.10	-
Furnace Oil (FO) (Optimal)(Deterministic)	-	354.21	579.99
Furnace Oil (FO) (Optimal)(Stochastic)	-	354.50	592.70
Light Diesel Oil (LDO) (Optimal)(Deterministic)	-	63.42	13.46
Light Diesel Oil (LDO) (Optimal)(Stochastic)	-	63.48	13.75

NOTE : All figures are expressed in Kcal/kWh.

It may be emphasized that fuel ratios (i.e., fuel-mix) across plants from monthly time series analysis exhibit substantial *ex post* fuel substitution possibilities during the period under study. Furnace oil may be substituted for coal in the case of Gurunanakdeb (Bhatinda) (IC = 440 MW), Indraprastha (IC = 284.1 MW), Badarpur (IC = 510 MW), Bhusawal (II) (IC = 210 MW), Kothagudam (A) (IC = 240 MW), Kothagudam (B) (IC = 220 MW), Kothagudam (C) (IC = 220 MW), Ramagudam (B) (IC = 62.5 MW), Harduaganj(C) (IC = 170 MW), and Durgapur Power Projects Ltd. (IC = 285 MW).

In an oil-fired power plant, like Trombay (Tata) (IC = 337.5 MW), a substantial amount of natural gas can be substituted for LSHS/HSHS or RFO variant. In addition, the optimality in the substitution of furnace oil for lignite is exhibited in Neyveli Lignite Corporation (IC = 600 MW), belonging to the Tamil Nadu Electricity Board. The hypothesis of *ex post* fuel substitution is further substantiated in Tables 8.6 to 8.10 where optimal fuel quantities for different technologies are illustrated.

In the foregoing analysis it is amply demonstrated that the stochastic variant of the methodology proposed does allow fuel substitution *ex post* in steam electric power generation process where the expansion path is non-linear.

8.5 MEASURES OF INEFFICIENCY

We adopt a procedure similar to that of Chapter 7, Section 4. The new dimension added to the stochastic model is the incorporation of planned utilization rate (PUR) instead of capacity utilization rate (CU). The comparison will have to be done with respect to observed and optimal configurations of PUR in measuring the capital cost and fuel cost components of the planning inefficiency and the operational inefficiency. That is, one compares the physical magnitudes of HR and corresponding fuel consumption (Kcal/kWh), computed from fuel cost equation, to be optimal with respect to optimal CU for optimal PUR, obtained from the variable cost equation, with those calculated by substituting optimal CU for observed PUR in the fuel cost equation. The deviation is attributed to the fuel cost component of the planning inefficiency at the operational level. The operational inefficiency estimates are calculated from the discrepancy between (i) the values of the optimal HR and the corresponding fuel-mix with respect to CU for a given observed PUR, and (ii) values of HR and fuel choices in actual practice.

Moreover, the planning inefficiency at the system level is captured by the discrepancy between the optimal CU and the observed magnitudes in percentages. In the stochastic model, the optimal CU has two dimensions, viz., the optimality with

respect to both the optimal PUR and the observed PUR in practice for exogenous values of PLF and FOR. The capital cost per kWh is sensitive to both these dimensions of CU and PUR.

The different measures of inefficiencies are highlighted in consolidated Tables 8.2 to 8.10. In general, the operational inefficiency is overwhelming in relation to the fuel cost component of the planning inefficiency. The flat shape of fuel cost curves in the neighbourhood of minimum point has rendered it difficult to ascertain the extent of the planning inefficiency in some power plants, e.g., Nasik (IC = 280 MW), Bhusawal (I) (IC = 62.5 MW), Trombay (Tata) (IC = 337.5 MW), Dhuvaran (IC = 534 MW), Ramagundam (B) (IC = 62.5 MW), and Durgapur Power Projects Limited (IC = 285 MW). The observed values ofthe fuel quantities (i.e., fuel consumption Kcal/kWh) are reported in Tables 8.6 to 8.10.

Thus, the relative flat bottom of the cost curves underestimated the importance of the planning inefficiencies carried over to the operation level. But, we observe a significant capital cost component of the planning inefficiency. This is prominent among relatively older power plants irrespective of size.

8.6 COST IMPLICATIONS

We have established in Chapter 6, Sections 4 and 5 that system planners, such as the CEA and the Planning Commission, have been able to choose efficient stock of installed capacity with special reference to peak load appearing at the system grid (i.e., Regional grid). The system inefficiency estimates may be repeated in the stochastic model for power plants which are taken care of in the cross-section stochastic model. This will be done by substituting the optimal values of IC and CU of the power plant concerned in the capital cost equation and comparing the minimum capital cost with that computed with respect to actual IC and corresponding optimal CU. Note that this optimal CU refers to both the dimensions of PUR for exogenously specified values of PLF and FOR. An attempt will be made to perform these inefficiency calculations for few selected power plants, viz., Paras, Parli Vaijnatu, Kothagudam (A), Ramagundam (B), Panipat, Durgapur Power Projects Limited, and Indraprastha.

In the time series analysis, we will also try to compute the capital cost as well as the fuel cost components of the planning inefficiency, and the operational inefficiency.

The methodology adopted for the computation of inefficiencies is as follows :

(i) System Inefficiency : It is the difference between

(a) CC_1, the capital cost emanating from optimum values of IC, PUR and CU, and

(b) CC_2, the capital cost resulting from actual IC, optimum PUR and optimum CU corresponding to the above IC and PUR.

It is the deviation of

(ii) Capital cost component of Planning Inefficiency :

(a) CC_2, the capital cost as noted in (i) (b), from

(b) CC_3, the capital cost generated by actual averages of IC, PUR and CU in practice.

(iii) Fuel Cost Component of Planning Inefficiency : It is measured as the discrepancy between

(a) CC_4, the capital cost corresponding to actual IC, optimum CU, optimum HR and fuel-mix, and

(b) CC_5, the capital cost with respect to actual IC, actual CU and the corresponding optimum values of HR and fuel-mix.

(iv) Operational Inefficiency : It is represented as the difference between

(a) CC_5 as computed in (iii) (b), and

(b) CC_6, the capital cost obtained from actual observed averages of IC, CU, HR and fuel-mix.

Paras, a small power plant, yielded the following estimates.

System inefficiency = 3.05 paise (observed capital cost/ kWh = 3.60 paise)

Capital cost component of planning inefficiency = 2.34 paise

Fuel cost component of planning inefficiency = 0.11 paise

Operational inefficiency = 0.65 (in relation to observed fuel cost/kWh to be 14.0 paise)

Parli Vaijnatu, another small well-managed plant, has the following inefficiency estimates :

System inefficiency = 8.76 paise (in relation to observed capital cost/kWh 7.80 paise)

Capital cost component of planning inefficiency = 1.5 paise

Fuel cost component of planning inefficiency = 0.47 paise

Operational inefficiency = 0.07 paise (in relation to observed fuel cost/kWh 10.70 paise)

For Kothagudam (A), a relatively large (IC = 240 MW) plant , the inefficiency estimates turned out to be

System inefficiency = 1.7 paise (in comparison to observed capital cost per kWh to be 12.50 paise),

Capital cost component of planning inefficiency = 2.73 paise,

Fuel cost component of planning inefficiency = 3.27 paise, and

Operational inefficiency = 3.6 paise (in comparison to observed fuel cost/kWh to be 22.0 paise).

Ramagundam (B), another small well-run plant has :

System inefficiency = 8.27 paise (in relation to observed capital cost per kWh, 7.5 paise),

Capital cost component of planning inefficiency = 1.12 paise,

Fuel cost component of planning inefficiency = 0.13 paise, and

Operational inefficiency = 0.12 paise(in relation to observed fuel cost per kWh, 17.30 paise)

Panipat, a medium sized(IC = 220 MW) plant, entrusted to Haryana State Electricity Board, has the following estimates

System inefficiency = 2.01 paise (whereas observed capital cost/kWh is 15.0 paise).

Capital cost component of planning inefficiency = 2.45 paise.

Fuel cost component of planning inefficiency = 2.21 paise.

Operational inefficiency = 2.52 paise (whereas observed fuel cost/kWh is 39.0 paise)

The derived inefficiency measures of Durgapur Power Projects Limited, a coke-oven power plant, whose operational hazards have been very well documented, are

System inefficiency = 2.65 paise (observed capital cost/kWh is reported to be 8.0 paise),

Capital cost component of planning inefficiency = 1.17 paise,

Fuel cost component of planning inefficiency = 2.64 paise, and

Operational inefficiency = 3.28 paise (observed fuel cost/kWh is reported to be 24.0 paise).

Indraprastha power station, belonging to Delhi Electric Supply Undertaking (DESU), has generated the desired estimates as

System inefficiency = 1.65 paise (corresponding observed capital cost/kWh is 12.0 paise),
Capital cost component of planning inefficiency = 2.58 paise,
Fuel cost component of planning inefficiency = 1.29 paise, and
Operational inefficiency = 2.00 paise (corresponding observed fuel cost/kWh is 19.50 paise).

The results obtained so far are represented in a concise form in Table 8.11. If we compare Tables 7.11 and 8.11 we can easily demonstrate the superiority of the stochastic model over its deterministic counterpart. Though the general trend is similar, the estimates of system inefficiency have been fine tuned. The sensitivity of the capital cost equation in the stochastic model with respect to small unit size has been taken care of by the uncertainty parameters, viz., PLF and FOR explicitly introduced in the reformulation of the decision structure.

The relative flatness of the cost curves, once again, makes the distinction between the fuel cost component of the planning inefficiency and the operational inefficiency a bit difficult. Secondly, the cost implications of capital equipment and operation of different units within a plant have not been explored satisfactorily.

TABLE 8.11

STOCHASTIC MODEL: COST IMPLICATIONS OF MEASURES OF INEFFICIENCY

Sl. No.	Name of the Power Plant	System inefficiency (paise)	Capital cost/kWh (paise)	Capital cost component of planning inefficiency (paise)	Fuel cost component of planning inefficiency (paise)	Fuel cost/kWh(paise)	Operational inefficiency (paise)
1.	Paras	3.05	3.60	2.34	0.11	14.00	0.65
2.	Parli Vaijnatu	8.76	7.80	1.50	0.47	10.70	0.07
3.	Kothagudam (A)	1.70	12.50	2.73	3.27	22.00	3.61
4.	Ramagundam (B)	8.27	7.50	1.12	0.13	17.30	0.12
5.	Panipat	2.01	15.00	2.45	2.21	39.00	2.52
6.	Durgapur Power Projects	2.65	8.00	1.17	2.64	24.00	3.28
7.	Indraprastha	1.65	12.00	2.58	1.29	19.50	2.00

It may be noted that the estimates of inefficiency measures in physical quantities supported the hypothesis of predomination of the operational inefficiency over the system and planning counterparts. But, the results of cost implications are mixed in nature. The very shape of average cost curves does not permit the influence of the operational inefficiency to be translated into appropriate cost figures. Moreover, a small amount of planning inefficiency is magnified in the cost surface. It follows therefore that utility (plant) managers and planners should be cautious in adopting directives to different levels of hierarchy to execute least cost expansion plans of energy generation.

8.7 CONCLUSION

The major findings of this chapter are as follows :

(i) A substantial amount of _ex post_ fuel substitution is occurring at the individual plant level irrespective of the different technological constraints operating in the steam cycle process. Furnace oil may be substituted for coal, and lignite whereas natural gas may be substituted for fuel oil, e.g., LSHS/HSHS or RFO.

(ii) The capital cost component of the planning inefficiency is prominent among relatively old power plants irrespective of their sizes in comparison to new ones.

(iii) The fuel cost component of the planning inefficiency as carried over to the operational level is distinguishable from the operational inefficiency only when the average cost curves are not flat at the bottom.

(iv) The operational inefficiency, except in few well-managed and new power plants, is significantly large in magnitude. The results of cost implications are, however, mixed in nature.

(v) The sensitivity of the capital cost equation with respect to small installed capacity has been adequately taken care of by explicit incorporation of PLF and FOR figures as uncertainty parameters.

(vi) The optimality of CU has been discerned with special reference to two dimensions of PUR (e.g., observed and optimal magnitudes of PUR emanating from the conceptualization of variable cost per kWh at bus-bars).

So far we have been able to identify the measures of inefficiency of individual power plants over entire time period of the sample. One pertinent question will be - how far would the inefficiency estimates be sensitive to seasonal fluctuations in load growth (i.e., average load) on the system? This needs careful investigation at the load of each of the power plants in a disaggregative fashion. This will be attempted in the next Chapter.

CHAPTER 9

SEASONAL VARIATION IN THE DECISION MAKING EFFICIENCY

9.1 INTRODUCTION

In the present study, efficiency of a power plant has been defined with respect to the least cost of delivering a kWh of energy at the bus-bar. All analytical work in the modern thermal power plants, based on the Rankine Vapour Cycle[1], defines efficiency as the ratio of heat equivalent of the operations of the cycle to net enthalpy of the liquid measured in Kcal per kg[2]. Thus, our analysis is analogous to the engineering studies of the efficiency of steam electric power generation.

An exhaustive attempt was made in Chapters 7 and 8 to conceptualize different measures of inefficiency emanating

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1. A steam engine operating at a top temperature of 212°F and an exhaust temperature of 80°F would add 132 BTU at an average temperature of (212+80)/2 or 146°F, and would add 970 BTU at a temperature of 212°F, thus making a weighted mean temperature of heat addition of 203°F or 663°R. The Rankine efficiency of this cycle, then, is (663-540)/663 or 18.6 percent. Computations may change slightly due to varying heat capacity of liquid water as temperature changes.

2. For details, see Priest (1947). He defined plant efficiency as thermal efficiency (i.e., HR/860) per sent out kWh at the bus bar.

from the operational decisions of the managers of the power plants at various stages of production. Results of cost implications of these measures are mixed in nature. The adoption of measures of inefficiencies in physical terms was also highlighted.

But one question remains unanswered. Recall from Chapter 6 that as the average load on the system increases, the plants seem to perform better than during periods of slack demand. The load is not connected to the individual power plants due to technological reasons. The concept of grid (Regional or National) came into the picture to cater to the distribution of demand among inter-connected power plants. It follows that we implicitly presume that the efficiency of the plant corresponds to that which is obtained when the power plant operates to cater to the largest plant load factor.

In the cross-section analysis of stochastic model, the variable cost and capital cost equations do include PLF as an interactive term. The estimated coefficient for this variable turned out to be negative in most of the cases. A similar result was obtained even in the time series analysis of the stochastic variant of the estimated cost models.

In the present chapter we seek to verify the afore-mentioned hypothesis in the context of fourteen representative power plants in our sample. The sample covers

(i) coal-fired as well as oil and lignite fired plants, (ii) plants of old and new vintage, and (iii) large, medium and small power plants. A computer simulation model has been developed to assess the sensitivity of inefficiency estimates with respect to seasonal fluctuations in the average load (MkWh) for the plant concerned over the planning horizon.

9.2 THE HYPOTHESIS

The hypothesis put forward in this section is that there exists a direct relationship between the average load (MkWh) at the bus-bar and the efficiency of the operations of the concerned power plant. This may be tested both in the framework of the deterministic and the stochastic models. The following methodology has been proposed to pursue empirical verification of our hypothesis :

(i) Deterministic Model : The optimal CU is determined by satisfying first-order and second-order conditions of minimizing capital cost per kWh. This will be introduced into the fuel cost/kWh equation to obtain the optimal HR and the corresponding fuel combinations. The deviation of HR_2 (the optimal HR) and Z_{i2} (the optimal Z_i) (Z_i being the major fuel used for firing the boiler of the ith plant) from the corresponding observed magnitudes , viz., HR_1 and Z_{i1}, should give us the desired power plant inefficiency for a particular month. The procedure can be repeated for each

month of the planning period. The aforementioned Z_i may be coal (CO), oil (RFO) or lignite (LIG) depending on the power plant under considerations. One may observe the fluctuations in the inefficiency estimates over the months as the average load (MkWh) varies. The estimates of (HR_1-HR_2) and $(Z_{i1}-Z_{i2})$ are expressed in Kcal/kWh.

(ii) Stochastic Model : Here, three stages of the decision making process will have to be distinguished. The optimal configurations of CU, PUR and HR along with fuel-mix are executed at three levels of hierarchical structure. Once the well-selected installed capacity is handed over to individual plant managers, one group of decision makers (i.e., one wing or cell of plant management) decides PUR on the basis of the variable cost considerations with special reference to uncertainty parameters, e.g., PLF and FOR. The utilization rate to be delivered (CU) is chosen purely by minimizing the capital cost per kWh for a given optimal PUR along with exogeneously specified PLF and FOR variables. This optimal CU is substituted in the fuel cost per kWh equation to generate the optimal HR and fuel combinations. We conceptualized two inefficiency estimates in this context, viz., the discrepancy between (a) CU_2 (the optimal CU for a given optimal PUR, and observed PLF and FOR) and CU_1 (the actual observed average for the month under consideration),

(b) HR_4 (the optimal HR) and the corresponding Z_{i4} (the optimal major fuel of ith plant with respect to optimal CU for a given optimal PUR along with actual averages of PLF and FOR), and HR_3 and Z_{i3} which are the actual observed quantities expressed in Kcal/kWh for a particular month.

The former estimate (CU_1-CU_2) is expressed as a percentage whereas the latter (HR_3-HR_4), and (Z_{i3}-Z_{i4}) are measured in Kcal/kWh. The procedure will be repeated for all the months over the planning horizon. The variable Z_i may be coal (CO), oil, residual fuel oil (RFO) or lignite (LIG) as per specification of the technology of the particular power plant. It may be noted that seasonal variations with respect to the average load (MkWh) on the power plants resulted in pronounced variations in the efficiency of operations.

One observation is in order. The monthly averages HR_3 and Z_{i3} in the stochastic model are the same as HR_1 and Z_{i1} in the deterministic specification. The notation is changed for convenience. Moreover, we have deliberately avoided the cost implications of our inefficiency estimates which may give rise to same hypothesis under certain qualifications.

9.3 EMPIRICAL VERIFICATION

A sample of 14 power plants has been selected out of a population of 26 plants. This mostly represents technological diversity due to plant size, major boiler-firing fuel and synchronization of units within a plant. The plants in the sample face common operational problems[3].

Tables 9.1 to 9.14 document the measures of inefficiency in the deterministic as well as the stochastic framework with special reference to all the relevant months over the entire period of study. Since the time spans of different plants studied are not identical, the period under study and IC are reported separately. Asterix marks are given to the maximum and minimum values of average load (MkWh) which occured during the period under consideration. The lowest and the highest estimates of inefficiencies do correspond to maxima and minima of the load growth with a few exceptions. In the deterministic model, the max-min of average load is matching perfectly with that of (HR_1-HR_2) in several plants (e.g., Bhatinda, Faridabad, Panki, Harduaganj (B), Nasik, Bhusawal (I), Paras, Trombay (Tata), Koradi, Dhuvaran, Ukai, Ennore, Neyveli and Barauni). However, (Z_{i1}-Z_{i2}) does not match in plants like Bhatinda, Nasik, Trombay (Tata), Dhuvaran, Ukai, Ennore and Neyveli. This may be due to

3. For details, see Central Board of Irrigation and Power (1975, 1976).

TABLE 9.1

GURUNANAKDEB (BHATINDA) (IC=440 MW)

(JANUARY 1980 - MARCH 1981)

	DETERMINISTIC MODEL		STOCHASTIC MODEL		
LOAD (MkWh)	HR_1-HR_2 (Kcal/kWh)	CO_1-CO_2 (Kcal/kWh)	CU_1-CU_2 (percentage)	HR_3-HR_4 (Kcal/kWh)	CO_3-CO_4 (Kcal/kWh)
287.5	15.28	16.13	52.97*	4.87	5.82
276	17.35	20.38	52.76	7.21	10.61
322	-1.73	4.83	42.78	-12.09	-4.86
302.5	9.71	14.71	31.69	2.81	8.19
272	14.56	18.22	36.34	7.16	11.13
343	-2.68	2.07*	34.38	-11.05	-5.91*
283	11.48	13.75	46.79	1.83	4.35
270	14.11	18.34	47.35	4.65	9.35
300	6.69	13.18	37.90	-1.65	5.41
283	11.19	19.69	41.43	2.60	11.93
382*	-4.88*	4.73	14.32*	-18.56*	1.40
287	15.06	19.52	39.11	7.22	12.09
263	18.13	21.18	36.73	11.00	14.32
258*	20.98 *	23.48*	42.47	13.12*	15.87*
314.5	-0.24	7.67	25.89	-6.43	1.97

TABLE 9.2

FARIDABAD (IC = 120 MW)

(JANUARY 1980 - JUNE 1981)

	DETERMINISTIC MODEL			STOCHASTIC MODEL	
LOAD (MkWh)	HR_1-HR_2 (Kcal/kWh)	CO_1-CO_2 (Kcal/kWh)	CU_1-CU_2 (percentage)	HR_3-HR_4 (Kcal/kWh)	CO_3-CO_4 (Kcal/kWh)
60	36.11	32.45	53.51*	33.95	30.16
92	32.04	29.08	19.70	31.23	28.24
93	26.29	28.61	-25.20	29.68	31.89
93	26.92	28.16	-26.54	28.07	29.29
120	-13.29	-13.10	-26.85	-17.62	-17.42
54*	56.07*	55.13*	25.91	54.17*	53.20*
58	34.37	34.61	20.65	33.48	33.72
107	26.73	27.22	22.51	25.58	26.08
115	6.65	10.01	-29.17	8.50	11.79
104	12.43	16.04	-5.16	12.73	16.33
103	15.40	17.20	-13.19	16.10	17.89
120*	-23.56*	-24.61*	-60.01*	-21.68*	-22.71*
117	-4.85	-12.12	-26.25	-6.27	-13.64
100	9.93	11.55	20.47	7.87	9.52
116	2.02	3.55	29.41	-0.39	1.18
115	6.66	8.64	31.25	9.97	11.88
114	5.74	7.05	-53.22	9.30	10.56
103	16.77	15.96	-29.67	18.34	17.56

TABLE 9.3

PANKI (IC = 284 MW)

(JANUARY 1980 - JUNE 1981)

DETERMINISTIC MODEL STOCHASTIC MODEL

LOAD (MkWh)	HR_1-HR_2 (Kcal/kWh)	CO_1-CO_2 (Kcal/kWh)	CU_1-CU_2 (percentage)	HR_3-HR_4 (Kcal/kWh)	CO_3-CO_4 (Kcal/kWh)
159	25.83	26.44	40.49	29.97	30.55
218	28.27	28.53	33.67	31.58	31.83
165	27.82	29.35	11.18	28.91	30.42
235	23.51	24.72	28.55	26.45	27.61
230	24.31	25.35	27.46	27.12	28.11
241	20.52	19.96	23.30	23.02	22.48
240	19.10	16.56	49.72	24.63	22.26
236	20.05	14.87	53.79	27.03	22.31
244	15.93	13.92	38.20	23.76	21.94
248*	14.87*	13.65*	4.20*	21.25	20.12*
225	25.81	25.35	8.81	29.66	29.23
242	16.49	19.53	7.41	17.48*	20.48
231	23.69	25.95	11.27	25.19	27.41
225	25.32	28.19	14.54	26.06	28.90
138*	48.81*	51.28*	66.44*	48.04*	50.55*
140	26.38	28.73	63.28	27.60	29.91
230	22.13	25.08	12.30	22.57	25.50
236	21.80	23.98	15.95	23.48	25.62

TABLE 9.4

HARDUAGANJ(B) (IC = 210 MW)

(APRIL 1980 - MARCH 1981)

	DETERMINISTIC MODEL		STOCHASTIC MODEL		
LOAD (MkWh)	HR_1-HR_2 (Kcal/kWh)	CO_1-CO_2 (Kcal/kWh)	CU_1-CU_2 (percentage)	HR_3-HR_4 (Kcal/kWh)	CO_3-CO_4 (Kcal/kWh)
170	9.32	6.38	25.95	6.54	3.51
166	12.64	6.65	27.22	9.85	3.67
165	13.04	5.75	44.64	8.50	0.83
150*	28.23*	11.13*	78.25*	21.90*	3.30
160	19.40	7.58	74.53	12.60	-0.22
160	18.05	2.79	64.96	11.95	-4.46
165	14.22	5.93	57.17	8.58	-0.25
210*	0.10*	-4.02*	16.70*	-5.31*	-9.66*
190	5.81	7.37	26.64	2.86	4.46
180	10.01	7.41	29.56	6.90	4.22
190	5.66	5.14	21.98	3.23	2.69
185	6.47	7.33	20.96	4.15	5.04*

TABLE 9.5

NASIK (IC = 280 MW)

(JANUARY 1980 - MARCH 1981)
(OUTLIER: JANUARY 1981)

DETERMINISTIC MODEL				STOCHASTIC MODEL	
LOAD (MkWh)	HR_1-HR_2 (Kcal/kWh)	CO_1-CO_2 (Kcal/kWh)	CU_1-CU_2 (percentage)	HR_3-HR_4 (Kcal/kWh)	CO_3-CO_4 (Kcal/kWh)
225	9.17	10.25	10.80	9.20	10.28
214	9.55	10.68	6.85	9.57	10.70
210*	10.04*	10.93*	11.55	10.07*	10.96*
240	7.89	9.09	15.44	7.94	9.13
241	7.86	7.16	26.94	7.93	7.24
245*	5.97*	8.21	24.90	6.04*	8.28
240	7.65	6.67	52.36	7.80	6.82
241	7.97	4.86*	69.44*	8.17	5.07*
238	8.04	6.24	36.62	8.14	6.35
240	7.77	7.28	11.99	7.80	7.31
238	8.05	8.01	16.19	8.10	8.06
240	7.58	7.49	6.27*	7.60	7.51
220	9.42	6.93	43.24	9.54	7.05
242	7.83	7.10	14.97	7.87	7.14

TABLE 9.6

BHUSAWAL(I) (IC = 62.5 MW)

(JANUARY 1980 - MARCH 1981)

DETERMINISTIC MODEL | STOCHASTIC MODEL

LOAD (MkWh)	HR_1-HR_2 (Kcal/kWh)	CO_1-CO_2 (Kcal/kWh)	CU_1-CU_2 (percentage)	HR_3-HR_4 (Kcal/kWh)	CO_3-CO_4 (Kcal/kWh)
57	1.04	1.72	-2.32	1.03	1.71
58	0.70	2.46	-4.84	0.68	2.44
60	-3.47	-2.07	-6.28	-3.50	-2.10
59	-1.99	-1.92	5.55	-1.96	-1.89
57	2.96	4.76	-7.70	2.93	4.73
55	6.90	9.30	-2.47	6.89	9.29
54	4.01	6.50	-8.98	3.97	6.46
52	11.95	13.22	28.43	12.07	13.34
50*	17.83*	13.70*	72.05*	18.10*	13.99*
59	-1.34	0.76	24.72	-1.23	0.87
60	-4.14	-1.64	-15.65*	-4.21	-1.72
59	-2.92	-0.93	-13.03	-2.98	-0.99
57	2.18	4.13	-10.19	2.13	4.09
58	0.45	2.50	-10.05	0.40	2.45
62*	-5.17*	-3.27*	-10.61	-5.12*	-3.22*

TABLE 9.7

PARAS (IC = 92.5 MW)

(JANUARY 1980 - MARCH 1981)

	DETERMINISTIC MODEL			STOCHASTIC MODEL	
LOAD (MkWh)	HR_1-HR_2 (Kcal/kWh)	CO_1-CO_2 (Kcal/kWh)	CU_1-CU_2 (percentage)	HR_3-HR_4 (Kcal/kWh)	CO_3-CO_4 (Kcal/kWh)
80	16.91	17.10	29.55	1.35	1.58
90*	-2.71*	-2.56*	3.76*	-24.60*	-24.41*
83	4.91	4.36	41.01*	-21.02	-21.71
82	22.89	22.71	39.21	2.83	2.60
81	15.92	15.99	23.83	3.15	3.22
83	7.52	7.78	20.55	-4.46	-4.16
84	3.86	4.13	21.05	-9.31	-9.00
75*	39.86*	39.89*	30.40	28.15*	28.18*
81	23.44	23.80	6.55	20.23	20.60
82	21.59	22.15	4.13	19.52	20.09
80	24.87	25.37	8.99	20.57	21.10
81	23.24	23.58	13.28	16.76	17.14
82	20.96	21.25	22.97	9.24	9.57
83	18.86	19.35	13.02	12.12	12.65
84	14.12	14.05	12.70	7.16	7.09

TABLE 9.8

TROMBAY (TATA) (IC = 337.5 MW)

(OCTOBER 1979 - MARCH 1981)

	DETERMINISTIC MODEL		STOCHASTIC MODEL		
LOAD (MkWh)	HR_1-HR_2 (Kcal/kWh)	OIL_1-OIL_2 (Kcal/kWh)	CU_1-CU_2 (percentage)	HR_3-HR_4 (Kcal/kWh)	OIL_3-OIL_4 (Kcal/kWh)
286	10.49	17.38	29.36	10.59	17.47
295	3.26	28.04	4.64	3.28	28.06
313	-1.14	26.61	-1.52	-1.14	26.60
315	-1.00	17.93	1.10	-1.00	17.94
267	0.23	9.95	0.56	0.24	9.95
264	1.69	23.64	-5.29	1.67	23.62
308	-2.82	8.63*	3.60	-2.81	8.64*
318	-4.36	9.25	15.75	-4.30	9.30
307	-3.36	16.20	3.21	-3.35	16.21
306	-1.48	19.01	-18.23	-1.56	18.95
319*	-5.91*	18.41	-17.43	-5.98*	18.35
247	6.61	14.66	20.50	6.68	14.72
175*	10.56*	27.82	34.80	10.69*	27.92
176	10.33	52.34*	45.16*	10.49	52.42*
289	6.36	49.97	22.28	6.44	50.01
318	-4.77	31.73	-3.49	-4.78	31.72
320	-5.04	28.79	-9.11	-5.08	28.76
315	-3.21	35.97	-22.75*	-3.30	35.91

TABLE 9.9

KORADI (IC = 680 MW)

(JANUARY 1980 - MARCH 1981)

	DETERMINISTIC MODEL		STOCHASTIC MODEL		
LOAD (MkWh)	HR_1-HR_2 (Kcal/kWh)	CO_1-CO_2 (Kcal/kWh)	CU_1-CU_2 (percentage)	HR_3-HR_4 (Kcal/kWh)	CO_3-CO_4 (Kcal/kWh)
450	35.54	36.39	-6.42	45.19	45.92
425	54.04	54.85	4.97	49.27	50.16
430	49.92	50.66	6.17	43.71	44.53
438	47.67	47.93	-2.13	50.07	50.32
425	50.60	50.10	1.61	48.97	48.46
399*	55.27*	53.64*	3.55	52.09*	50.35*
450	39.25	41.90	10.96	27.34	30.50
490	30.97	33.99	11.91	16.51	20.16
500	28.11	31.22	8.92	16.59	20.20
530	21.17	24.66	11.30	5.89*	10.05*
625*	-6.27*	-2.90*	-13.74*	23.56	25.98
450	32.74	32.55	1.88	30.60	30.41
445	42.62	42.30	18.40*	26.23	25.82

TABLE 9.10

DHUVARAN (IC = 534 MW)

(OCTOBER 1979 - MARCH 1981) (NO OF OUTLIERS: OCTOBER 1979 and MARCH 1980)

DETERMINISTIC MODEL STOCHASTIC MODEL

LOAD (MkWh)	HR_1-HR_2 (Kcal/ kWh)	RFO_1-RFO_2 (Kcal/ kWh)	CU_1-CU_2 (percentage)	HR_3-HR_4 (Kcal/ kWh)	RFO_3-RFO_4 (Kcal/ kWh)
495	5.06	16.74	35.02	5.55	17.16
517*	0.47*	15.53	4.57*	0.83*	15.84
517	1.19	10.13	16.30	1.42	10.34
504	4.08	7.41	24.98	4.43	7.75
508	4.08	2.86	21.03	4.37	3.16
470	6.56	3.21	26.22	6.92	3.58
499	4.83	17.70	35.47	5.33	18.13
477.5	5.70	9.48	36.33	6.20	9.96
400*	9.91*	15.83	49.04*	10.56*	16.44
511	3.60	18.50*	19.81	3.88	18.73*
479	5.47	9.54	13.33	5.65	9.72
465	7.43	8.03	29.47	7.83	8.42
517	2.77	-2.90	15.84	3.00	-2.66
517	2.09	-18.27	13.20	2.28	-18.04
517	2.38	-7.18	7.68	2.49	-7.06
510.5	3.90	-51.00*	16.90	4.14	-50.63*

TABLE 9.11

UKAI(IC = 640 MW)

(OCTOBER 1979 - JUNE 1981)

DETERMINISTIC MODEL | STOCHASTIC MODEL

LOAD (MkWh)	HR_1-HR_2 (Kcal/kWh)	CO_1-CO_2 (Kcal/kWh)	CU_1-CU_2 (percentage)	HR_3-HR_4 (Kcal/kWh)	CO_3-CO_4 (Kcal/kWh)
420	18.40	16.34	31.67	20.94	18.95
260*	25.12*	22.18	54.58	29.24*	26.46
297	19.56	15.23	28.94	21.87	17.67
268	22.35	12.09*	23.06	24.08	14.04*
285	22.81	18.08	16.89	24.08	19.43
372	20.83	20.64	14.01	21.92	21.73
381	20.97	25.17	12.15	21.91	26.06
323	21.34	21.12	4.67	21.68	21.47
290	22.12	21.07	22.66	23.87	22.85
415	19.58	17.92	71.52	25.89	24.35
417	19.85	14.97	53.95	24.16	19.54
323	22.91	18.50	48.38	26.62	22.42
420	18.23	17.90	55.38*	22.89	22.58
476	16.32	19.50	37.29	19.34	22.41
450	18.41	16.91	16.49	19.68	18.20
290	22.96	28.51*	15.29	24.10	29.57*
475	15.10	18.15	13.55	16.21	19.22
493	15.10	20.45	8.76	15.79	21.09
508	10.70	18.97	1.58	10.83	19.09
518	7.91	16.33	3.58	8.22	16.61
534*	7.04*	12.86	-4.05*	6.71*	12.55

TABLE 9.12

ENNORE (IC = 450 MW)

(OCTOBER 1979 - MARCH 1981)

DETERMINISTIC MODEL | STOCHASTIC MODEL

LOAD (MkWh)	HR_1-HR_2 (Kcal/kWh)	CO_1-CO_2 (Kcal/kWh)	CU_1-CU_2 (percentage)	HR_3-HR_4 (Kcal/kWh)	CO_3-CO_4 (Kcal/kWh)
225	8.57	10.39	60.45	9.95	11.74
367*	-3.89*	-5.39	19.39*	-2.59*	-4.07
352	-2.54	1.66	33.81	-1.59	2.57
215	9.25	10.39	38.55	10.24	11.36
260	4.62	4.92	43.49	5.71	6.00
305	0.59	2.69	45.98	1.86	3.93
295	2.15	1.27	35.71	3.12	2.24
290	1.68	10.75	43.56	2.78	-0.51
302	0.62	-1.52	43.52	1.73	-0.39
365	-3.88	-6.90*	52.68	-2.56	-5.53*
320	-1.67	-5.41	60.97	-0.13	-3.81
215	10.04	4.58	68.53*	11.61	6.25
277	5.43	8.79	63.80	7.01	10.31
170*	12.07*	10.83	66.07	13.58*	12.37
192	10.85	10.73	50.75	12.12	12.00
180	11.62	14.07*	47.26	12.74	15.15*
240	10.24	12.26	31.90	10.98	12.98
265	6.63	11.15	22.60	7.25	11.75

TABLE 9.13

NEYVELI LIGNITE CORPORATION (IC = 600 MW)
(APRIL 1980 - DECEMBER 1981)

DETERMINISTIC MODEL STOCHASTIC MODEL

LOAD (MkWh)	HR_1-HR_2 (Kcal/kWh)	LIG_1-LIG_2 (Kcal/kWh)	CU_1-CU_2 (percentage)	HR_3-HR_4 (Kcal/kWh)	LIG_3-LIG_4 (Kcal/kWh)
431	13.63	17.28	32.15	6.87	10.80
487	10.82	15.17	22.06	5.95	10.54
441	12.87	12.84*	39.13	4.64	4.61*
388	18.21	25.46	37.69	10.74	18.65
474	15.22	19.12	28.80	9.23	13.41
388	17.22	23.34	32.93	10.58	17.19
460	14.45	15.71	39.32	6.41	7.78
393	16.23	23.01	48.80	6.49	14.06
376	18.04	29.82	50.12	8.36	21.53
460	11.61	17.14	42.17	2.72	8.81
469	12.47	20.12	34.59	5.11	13.38
474	12.83	22.51	29.95	6.44	16.83
393	16.23	25.30	28.97	10.30	20.01
487	10.66	22.25	17.84	6.69	18.81
534*	3.71*	14.59	17.57*	-0.50*	10.85
441	16.33	25.59	33.52	9.60	19.60
338*	27.95*	41.85*	42.32	20.70*	35.99*
376	27.74	41.03	44.55	20.05	34.76
393	19.74	33.87	51.65*	9.95	25.81
474	13.83	29.47	41.77	5.23	22.43
520	8.42	24.90	35.29	0.61	18.50

TABLE 9.14

BARAUNI (IC = 145 MW)

(JANUARY 1980 - MARCH 1981)

DETERMINISTIC MODEL | STOCHASTIC MODEL

LOAD (MkWh)	HR_1-HR_2 (Kcal/ kWh)	CO_1-CO_2 (Kcal/ kWh)	CU_1-CU_2 (percen- tage)	HR_3-HR_4 (Kcal/ kWh)	CO_3-CO_4 (Kcal/ kWh)
79	1.95	-0.86	16.33	3.59	0.81
71.5	2.47	1.25	18.88	4.34	3.14
78	0.22	-4.82	32.02	3.52	-1.35
95*	-7.39*	-9.01*	-30.49*	-4.10*	-5.67*
80	-2.74	-4.93	28.80	0.24	-1.89
51	12.13	9.40	21.96	14.04	11.37
46.5*	36.18*	33.19*	55.43	39.86*	37.04*
51	28.41	26.47	28.15	30.48	28.60
49	31.77	26.86	59.93*	36.05	31.45
52	15.74	5.53	45.86	19.73	10.00
66	5.94	4.41	-3.76	5.59	4.04
61	10.47	9.95	-11.37	9.45	8.93
84.5	0.97	-0.88	-5.62	0.41	-1.44
49.5	19.81	16.41	- 0.20	19.79	16.40
50	22.19	22.27	-1.90	22.05	22.12

inventory policy of fuel stock for the station concerned. In the stochastic framework, (HR_3-HR_4) and (Z_{i3}-Z_{i4}) are corresponding to the max-min of average load in the case of Faridabad, Bhusawal (I), Paras and Barauni plants. The planning inefficiency estimate, viz., (CU_1-CU_2) is remarkably comparable to the load in Panki, Harduaganj (B), and Dhuvaran stations. In several cases, either the maximum or the minimum values of inefficiency estimates are at par with that of average load. It implies that the planning and operational inefficiency is lowest (highest) corresponding to the maximum (minimum) average load on an average. This proves our hypothesis.

9.4 CONCLUSION

Thus, we notice that, in general,

(i) The operational inefficiency in the deterministic model, i.e., (HR_1-HR_2) and (Z_{i1}-Z_{i2}), is the maximum (minimum) corresponding to the minimum (maximum) of average load specified on the plant concerned, during the period under consideration.

(ii) The planning and operational inefficiency in the stochastic framework, i.e., (CU_1-CU_2) and (HR_3-HR_4), and (Z_{i3}-Z_{i4}) are the lowest (highest) when the average load at the bus-bar is the highest (lowest) over the time span for the power station under study.

Hence, it can be maintained that there exists a direct relationship between power plant efficiency and average load (MkWh) on the concerned plant.

CHAPTER 10

SUMMARY AND CONCLUSIONS

10.1 THE PERSPECTIVE

Electrical power provides one of the most convenient forms of energy for consumption in a vast range of applications. The provision of electricity undoubtedly is a necessary precursor to economic growth and development in India. As thermal generation would continue to contribute a major share of electric power in our country, the crux of the problems of reliability in thermal power technology hinges very much on the reliability and efficiency of thermal power stations. To meet these challenges it is most important that a fresh look is given to the proper management of power systems in this country.

A coherent attempt has been initiated in the present study by defining the provision of power as efficient if a Kilowatt hour of energy is delivered at the lowest possible cost at the bus-bar. The presumption that there exists inefficiency in actual operation of power plants is indicated by two common observations. (i) There has been a substantial discrepancy between the planned utilization rate and the actual capacity utilization. (ii) The actual heat rate and the fuel-mix combinations (expressed in Kilocalories per

Kilowatt hour) in use are widely different from the technologically determined optima.

The study proposed that the observed inefficiency may itself be due to one or more of the following factors :

(i) system inefficiency in the choice of installed capacity,

(ii) inefficient planning in the determination of the rates of utilization, and

(iii) operational inefficiency due to improper choice of heat rate and consequently the corresponding fuel choices.

These aspects can be examined appropriately only when the institutional and technological constraints on the decision making process are kept in proper perspective. To this end the following dimensions of the problem have been emphasized in the present work :

(i) The decisions regarding installed capacity and actual operations are entrusted to different levels of management who presumably have different objectives,

(ii) The supply process of steam electric power generation is made inherently stochastic due to the existence of forced and partial outages. The demand for power is also subject to random fluctuations over days of a week, months of a year and so on. The input choices must account for these production and demand uncertainties efficiently.

(iii) The inputs and outputs of steam electric power plants are multidimensional and each of these aspects has a differential impact on the overall cost.

(iv) The *ex ante* and *ex post* input choices are not identical. Any analytical framework which attempts to integrate these factors should also be able to distinctly identify the extent of inefficiency attributable to each of the three dimensions mentioned earlier.

10.2 METHODOLOGY

A perusal of the literature indicated that there are three primary methods of examining the fuel substitution possibilities in the context of power plant economics :

(i) the production function approach,

(ii) the input demand approach, and

(iii) an analysis of the cost functions.

Extensive search of the analytical as well as empirical experiences indicated that the cost function approach is the most efficacious. Consequently, the study was developed on this basis.

Structurally, the hierarchical form of decision making necessitated writing the cost function for the capital cost component and operating costs separately. This had to be done in the deterministic as well as the stochastic formulations. The cost decomposition technique, in the stochastic model,

treated fuel cost, operating cost and capital cost individually with special reference to the organisational set up. Secondly, the multi-output and *ex ante* versus *ex post* distinctions were incorporated in all the cost functions following established conventions[1]. Thirdly, the effect of stochastic supply variation on input choices was introduced by recognizing that forced outages require revaluation of the utilization rates and fuel-mix choices. The formulation enabled us to demonstrate that the different forms of inefficiency can be isolated by using this approach. Moreover, demand uncertainty captured by plant load factor has also been successfully taken care of by the cost functions attributable to the stochastic model.

10.3 EMPIRICAL RESULTS

Empirical work is reported for a sample of twenty six power plants based on their monthly performance. Firstly, a synthetic cross-section was developed with reference to the peak demand quarter in an year to examine the optimality of the *ex ante* choices of installed capacity, rate of utilization, and the heat rate along with the corresponding fuel-mix

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1. Since expansion paths of power plants are non-linear, we have incorporated factor proportions along with the index of output in the fuel cost equation to determine optimal HR and fuel-mix. The inter-fuel substitution has been observed along an iso-cost curve given the factor prices.

combinations. The results indicated that the actual installed capacity is generally close to the optimum determined by minimum cost considerations. Allowing for the stochastic variations improved the closeness of these figures. However, the actual rate of capacity utilization differed considerably from the optimal. Thus, it appears that despite an appropriate choice of installed capacity, there was inefficiency in the planned rates of use. Secondly, cost estimates were obtained for each plant on the basis of the monthly time series data. Optimal levels of planned utilization rate (PUR), capacity utilization rate (CU) and fuel-mix were developed for both the deterministic and stochastic variants of the model proposed. It was demonstrated that there were significant disparities between the observed PUR, CU, heat rate and fuel-mix, and the optimal values so computed. The actual heat rate and fuel-mix were not optimal even if the observed PUR and CU were taken to be optimal. Similarly, the analysis clearly indicated that the operational management was inefficient. They perhaps do not undertake cost minimization strategies as much as they ought to.

It may, however, be noted that the present work points out the existence of a substantial magnitude of *ex post* fuel substitution which is occurring at the individual plant level irrespective of different technological constraints

operating in steam cycle process. Furnace oil may be substituted for coal or lignite whereas natural gas may replace fuel oil, e.g., LSHS/HSHS or RFO variant. Thus, there exists *ex ante* and *ex post* fuel substitution across power plants during the period under consideration. The pertinent interdependent hierarchical structure of decision making has been identified with consequent quantification of the extent of measures of inefficiencies at the system, planning and operational levels.

The capital cost component of planning inefficiency is prominent among the older vintage power plants irrespective of their sizes. The fuel cost component of the planning inefficiency as carried over to the operational level is distinguishable from operational inefficiency only when the average cost curves are not flat at the bottom. The operational inefficiency, in turn, except inafew well-managed and new power stations, is significantly large in magnitude. The results of cost implications are, however, mixed in nature.

A monthly simulation of the different aspects of inefficiency was then undertaken to analyze the possible difference in the performance at different load factors. A direct relationship between average load (MkWh) and power station efficiency was discernable. In other words, the

operational management of power plants tends to be reasonably efficient only when there is a necessity to deliver large volumes of energy.

10.4 FEW SUGGESTIONS

Immediate attention has, therefore, to be given to restructuring of the weakest links in the power systems, which are :

(i) Emphasis should be given to reliability in operation and for quality and timely maintenance of the plant and equipment. Predictive and preventive maintenance should be given much more importance in the entire set-up. Needless to say, routine and running maintenance should also get equal priority.

(ii) A fresh look should also be given to control and instrumentation[2] and the development of the necessary expertise for the operation and maintenance of the automatic controls and effective protection systems.

(iii) Spares management, both by manufacturers and users should receive much higher attention and top priority.

iv) Incorporating and introducing design improvements, particularly to suit the local conditions, such as modifications in boilers for high ash Indian coals,are indicated.

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2. It implies automation of (i) control and regulation of steam flow, feed water flow, water level in boiler drum (ii) steam temperature and pressure control (iii) combustion and drought control (iv) mill plant control (v) voltage regulation and frequency control.

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